

Basic Mud Logging



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1. WELL PLANNING

Before a new well is drilled a well plan has to be developed. There is a number of different companies involved in making the hole and a well plan requires close liaison between them.

A little later we will look at the relationship between the different companies but let's first consider the major bodies involved in the operations.

1. Operating company

The operating company is the oil or gas company which has a licence to drill for and produce petroleum within a specified area. The actual licence may be held by a number of companies who are working as a partnership. In such a case one of the partners is usually nominated as "the operator".

2. Drilling contractor

To do the actual drilling of the well the operator will employ a drilling contractor. Usually, the contractor is the owner of the drilling rig and is responsible for providing the personnel who make up the drilling crew.

3. Drilling service companies

As you will shortly see, there are many special drilling services required during the drilling of the well. It is the responsibility of the operator to engage these companies and coordinate their activities.

4. Logistical support services

Supply of equipment, materials and personnel to and from the drill site has to be arranged and coordinated. In offshore, this will involve the use of aircraft, helicopters and supply boats. In Onshore, conventional land transport will be required. Once again it is the responsibility of the operator to organize all this.

The well is drilled in a series of stages. At each stage, different kinds of problems are encountered. It is crucial to try to anticipate these problems in order for the drilling crew to take the necessary measures to minimize their effect.

In order to do this, the operator's drilling department will collect as much information as possible about the nature of the formations through which the well will be drilled. This information should include:

1. Expected total depth of the well.
2. Types and thicknesses of different rock formations to be drilled.
3. Expected formation pressures.
4. Depth and nature of any troublesome formations that may be encountered.

If the well is being drilled as a development well in an area where there are other wells, this information is readily available. However, if the well is an exploration well in a new area, the information is scarce and hence, much has to be inferred from the seismic surveys.

Having collected and collated all available data, the drilling department of the operating company will develop the drilling programme.

5. DRILLING PROGRAMME

This programme is a detailed step by step procedures for drilling the well. It is divided into a number of sub-programmes:-

1st.Casing and cementing programme

This programme specifies the type and length of the casing required for each hole section. This will be discussed later in detail at “Casing and Cementing”. There you will see that casing can be subjected to tremendous loads. By anticipating the maximum loads which can be imposed on the casing, the required strength and steel qualities can be determined and specified.

The programme will also specify the type and consistency of cement to be used to bond the casing to the drilled hole. In addition, any additives which may be required will be indicated.

2nd.Bits and Hydraulics programme

This programme will specify the type of bits, nozzle sizes and mud circulation rates for each section of the hole.

3rd.Mud programme

The mud programme specifies the mud properties which must be maintained during the drilling of each phase of the well.

4th.Drilling procedures programme

This programme gives instructions to the drilling contractor and operating company representatives regarding procedures to be followed.

The type of information which may be included in such a programme include :

- Bottom hole assemblies to be used.
- Equipment inspection procedures.
- BOP testing procedures.
- Suggested remedies for expected hole problems.
- Drilling parameters like rotary speeds (RPM), weights to be used on bits (WOB) ...etc.

Drilling a well costs a considerable amount of money. Proper advance planning however can control this expenditure. This is why the drilling programme is such an important part of the process of making a hole.

2. RIG TYPES & COMPONENTS

6. LAND RIGS

Land rigs vary considerably in size, lifting capacity, power generation, ability to circulate fluids... etc. See [figure 01](#) below for an example of a land rig.



7. OFFSHORE RIGS

a) JACK-UP RIGS

A Jack-up rig is a movable platform that can be jacked up and down three or four supporting legs. It supports drilling in relatively shallow water depths (down to 400 feet). To move rig between close locations the platform is lowered down the legs till it floats then the legs are jacked up to the maximum height. The whole rig can then be towed by means of two boats. In long rig moves or across oceans the whole rig is normally carried on a huge carrier.

Jack-up rigs are the most utilized type of rigs nowadays. Recently, legs design has been modified to support drilling in deeper waters. See [figure 02](#) below.

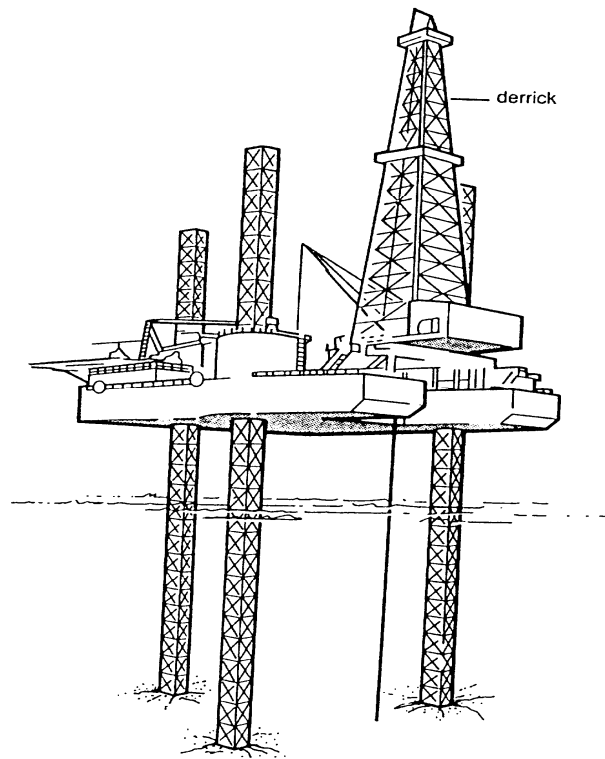


Figure 02

The following lists some advantages and disadvantages of the Jack-up rigs:

A d v a n t a g e s

1. Provides a fixed platform at low initial cost.
2. Can operate in soft bottom deltas.
3. Can withstand storms.
4. Does not need marine risers or sub-sea stack.

Disadvantages

1. Poor safety records.
2. Difficult to tow.
3. Has moving parts in jacking mechanism.
4. Hazardous for going on and off locations

b) SEMI-SUBMERSIBLES

A semi-submersible is a floating drilling rig. A typical layout is shown below in **figure 03**.

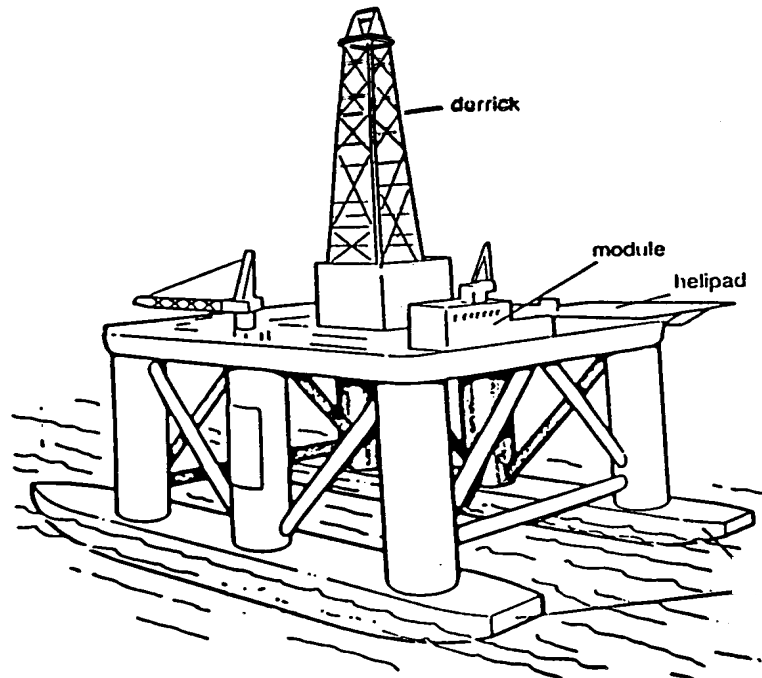


Figure 03

The following are some advantages and disadvantages of Semi-submersibles:

A d v a n t a g e s

1. Has a good safety record.
2. Provides a relatively stable platform.
3. Can function under more severe weather conditions.
4. Can drill in deep water - up to 2000 ft.
5. Can be self-propelled.

D i s a d v a n t a g e s

1. Requires marine risers and a sub sea stack.
2. Has a limited cargo capacity.
3. Requires support vessels.

c) DRILL SHIPS

These are special types of ships that are built for deep water drilling. They range in length between 200-450 feet. Their cargo carrying capacity and general mobility make them especially useful for drilling in remote areas. An example is shown in (figure 04) below.

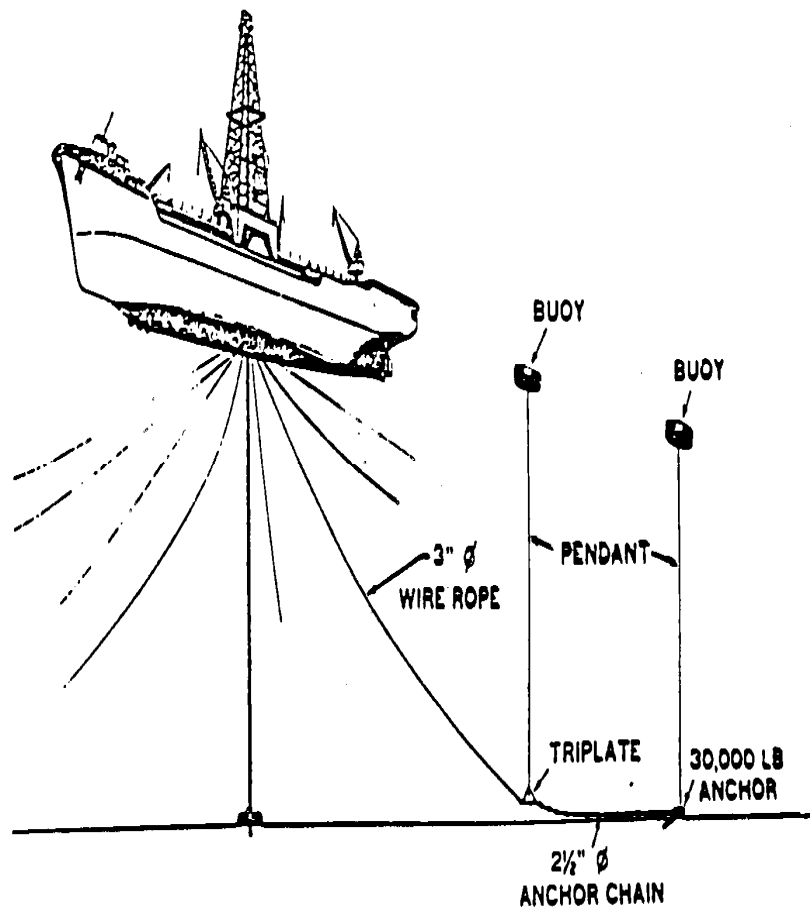


Figure 04

Some advantages and disadvantages of drill ships are:

Advantages

1. High carrying capacity.
2. Can drill in remote areas.
3. Can operate in deep water.
4. Self propelled.

Disadvantages

1. The lack of suitable risers to support drilling mud circulation between well head and drilling floor.
2. Not as stable as jackups and semi-submersibles.
3. requires a subsea stack.

8. D.PLATFORM RIGS

A platform is a fixed installation offshore from which development drilling and petroleum production is carried out. A steel platform design is shown as an example in **figure 05** below.

The deck, supported by a steel jacket, carries equipment, accommodation modules and a helicopter pad (helideck). It also supports one or more drilling rigs with associated equipment.

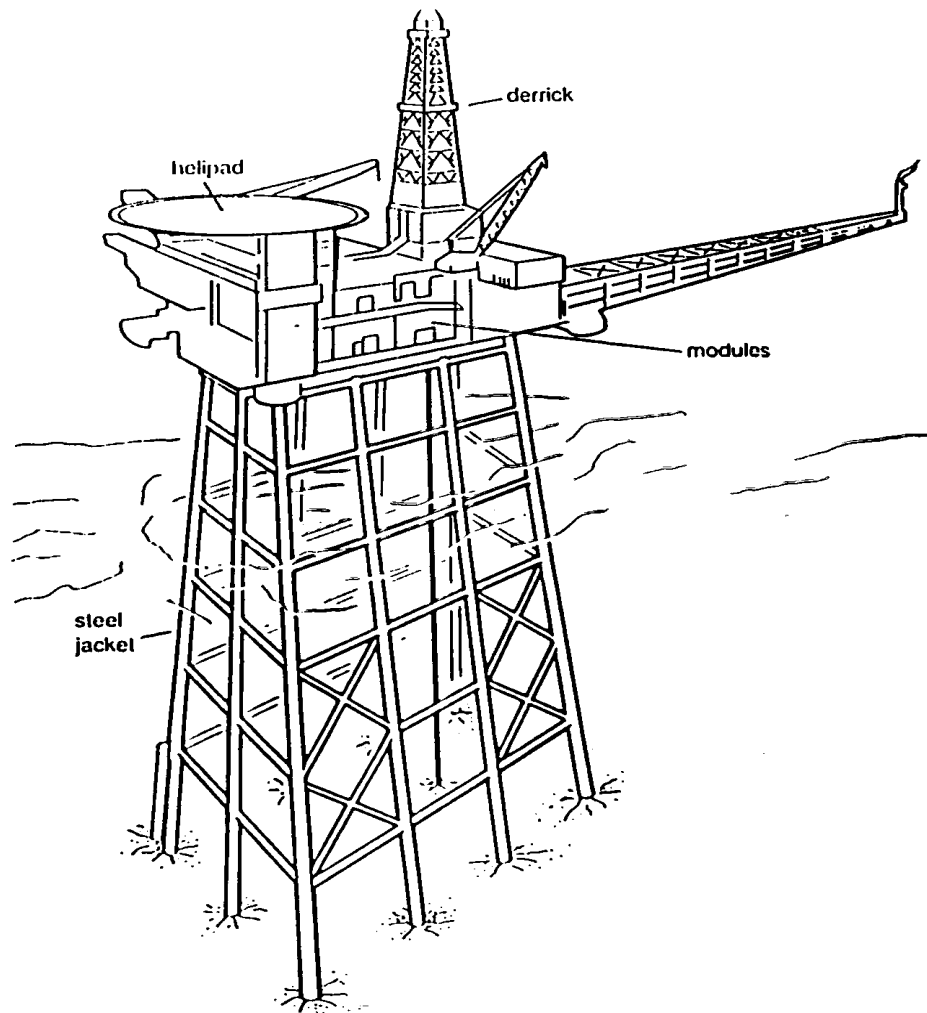


Figure 05

9. THE DRILLING TYPES

The basic function of a drilling rig is to drill a bore hole. This hole must be drilled in an accurate, economic and safe way. Drilling rigs are of two main types: **rotary** and **cable tool**.

1. Rotary drilling:

The rotation is generated either by a rotary motor to a rotary table or a top drive motor that directly rotates the drill string. The rotary table transfers power to the bit via the rotary and kelly bushings. Weight is supplied by allowing a small amount of the drill string weight to rest on the bit.

2. Cable tool drilling:

With the wireline method, a cable is used to connect the bit to the surface and a pounding motor is used to effect the weight on the bit.

RIG COMPONENTS

Rigs are made up of various components. However the following discussion is restricted to land rig components, most of these components are also found offshore.

Jack up rigs and fixed platforms are very similar to land rigs. They are not subject to wave and tidal movements as being fixed in relation to the sea bed during drilling operations. Therefore, they have no need for heave components or sub sea stack BOP's.

In the following few pages we will discuss the main components of drilling rigs taking land rigs as an example.

10. LAND RIG COMPONENTS

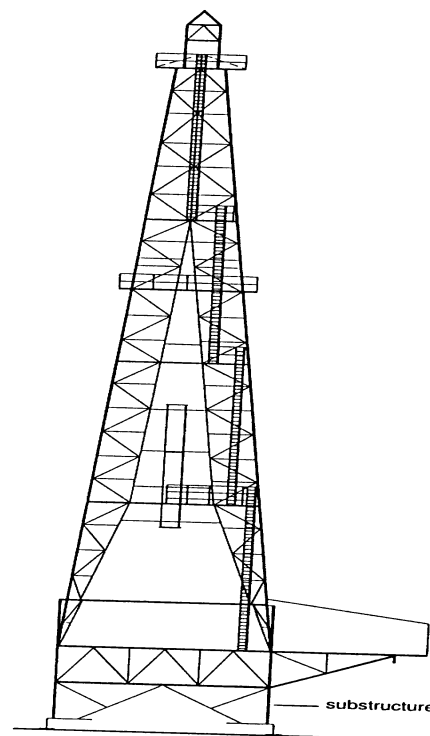
1. Mast or Derrick

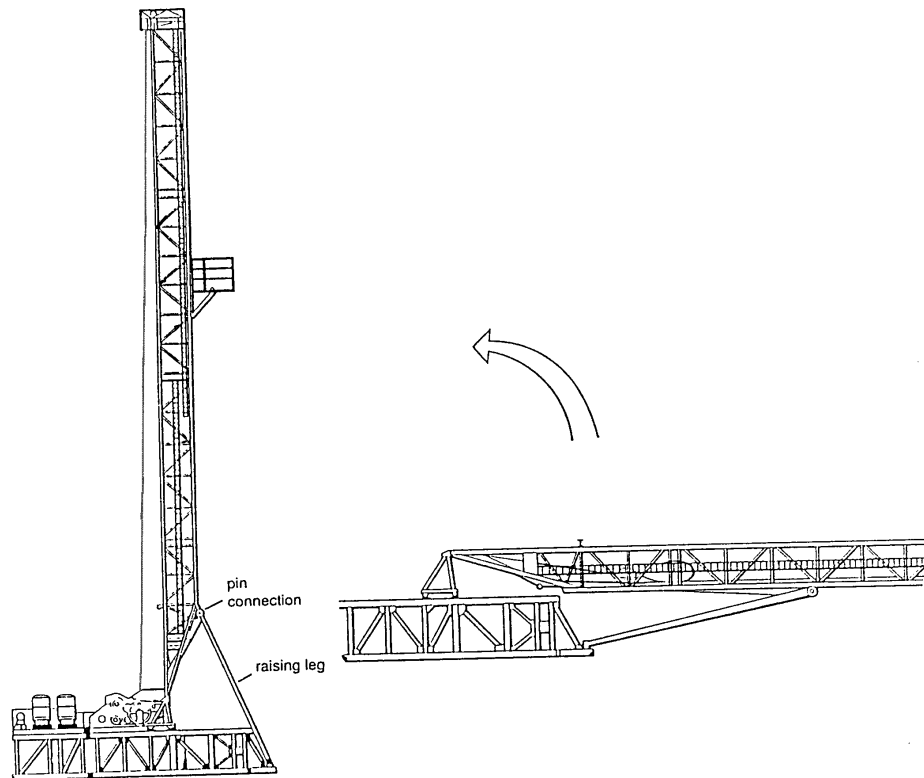
a) M a s t s

Masts are assembled on the ground from large welded sections fastened together with pins. They may then be raised to the vertical position by using the rig's own power unit and hoisting line. Small masts may be truck mounted while some are telescopic. This rigging-up time for masts tends to be less than that for conventional derricks.

Rigging-up time is the time spent to assemble a mast into the vertical position on-site. It also includes the time to install the power unit, all cables and piping. Masts are used for lighter work. Cantilever masts (also known as jack-knife derricks) are also common. **Figure 06** shows a typical mast layout.

(Fig. 06)



**Figure 07**

b) D e r r i c k s

There is no clear-cut distinction between a mast and a derrick. Often, the two terms are used interchangeably.

To keep things simple we will regard a derrick as the framework-tower type of support usually associated with oil well drilling. Typically derricks are assembled on-site bolting individual pieces together. The rigging-up time for this method is of course, longer than for a cantilever mast. (Figure 07)

2. Substructure

This is the support on which the derrick rests. It also acts as a support for the heavy equipment on the rig floor. The top of the substructure varies in height from 10-30 feet above the ground. This clearance is provided so that wellhead equipment can be installed underneath the rig floor. (Figure 08)

3. V-Door

This is a triangular opening on the front of the derrick to allow drill pipe and equipment to be picked up from the catwalk and brought into the derrick.

4. Monkey Board

This is a platform situated at a specific height from the rig floor, typically 60 to 90 feet, on which the derrickman works during trips. This platform also supports the fingers that are used to rack the stands of drill pipe .



Figure 08

5. Crown and Crown Blocks

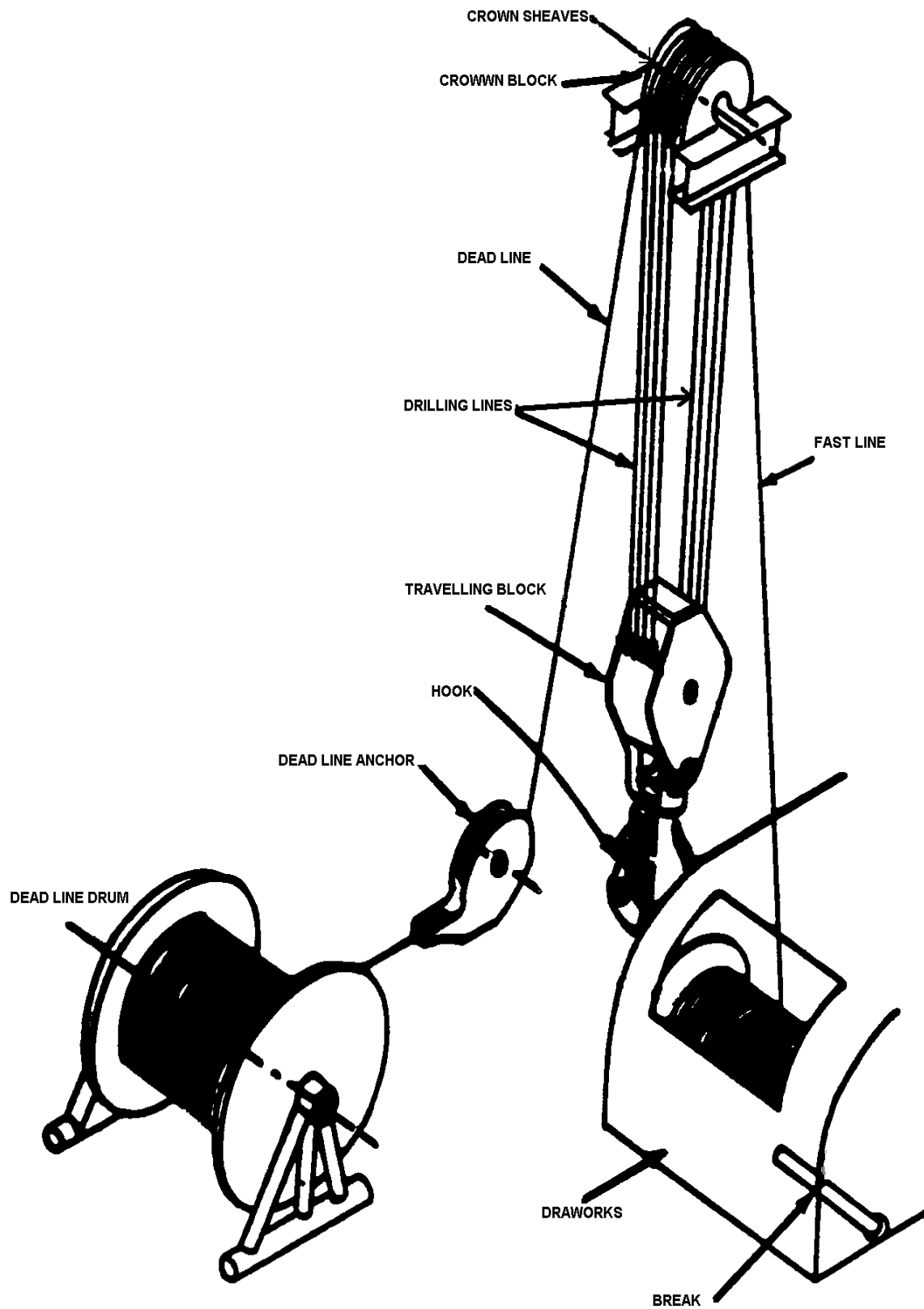
The top of the derrick is known as the crown, it is usually a small platform designed to carry the crown blocks. The crown blocks are the uppermost set of sheaves on which the drilling line is strung, most crowns of recent manufacture have from four to six sheaves. (Figure 09)

6. Travelling Block

This is merely the travelling pulley (sheave) assembly that is slung from the crown blocks by the drilling line. It connects the drilling line to the hook and swivel. (Figure 09)

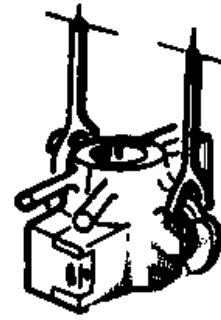
7. Hook

This is suspended directly from the block. It is composed of a main hook which carries the swivel bail and two smaller offset hooks carrying the elevator arm bails. The hook can rotate in the axis of the travelling block, limited by a lock device ; it is also sprung. (Figure 09)



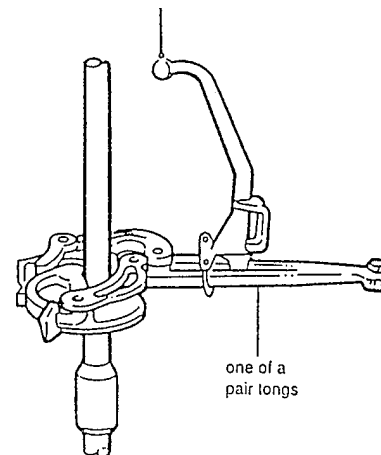
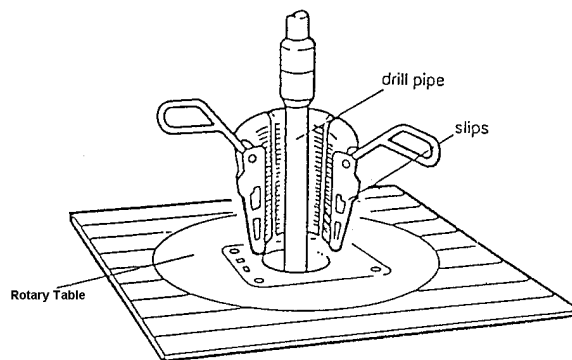
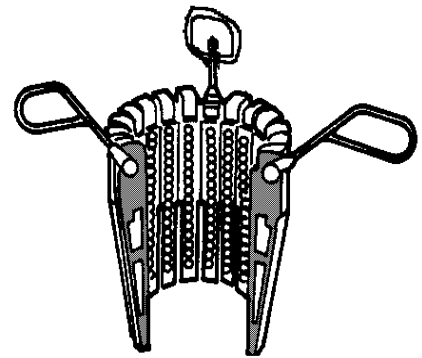
8. Elevators

Two elevators are hung from the hook on the elevator bails and are used for latching around the drill pipe in order to lift it. Elevators are of many slightly differing designs and sizes for use with different pipe sizes, drill collar and casing sizes. They are not used during the drilling operation but are necessary for lifting the pipe during a trip. **Figure 10)**



9. Slips

These devices are used to hold the weight of the drill string when it is not supported by the hook (during connections or tripping time). Slips are made of hinged sections with a single opening. They are placed around the pipe, their tapered outer sections fitting against either the inside surface (bowl) or the master bushing or against the inserts. As the pipe is lowered, the slips tapered section causes them to close tightly around the pipe. **(Figure 11)**



10. Tongs

A pair of special type of spanners is used to breakout and; or to tighten the pipe connections. One of the tongs is called “Back-up” and is attached to the drill pipe and is anchored to the derrick structure by a chain.

The other one is attached by to the connected pipe box or saver sub to be unscrewed and is connected via a chain to the Cat-head of the draw works. The rotation power of the draw works is used to breakout or tighten the connection.

On most modern rigs “Power Tongs” are used instead, They are hydraulically self operated able to breakout the connection without the use of chains. These are safer devices. **(Figure 11)**

11. Prime Movers (Engines)

The majority of the rig power is consumed by two operations :

- A. Circulation of the drilling fluid.
- B. Hoisting and/or Rotating.

These two operations could occur at the same time. The power consumption of the circulation system is essentially constant, where in the hoisting the prime movers must be capable of handling highly variable loads at rapid acceleration over a wide range of speed and torque.

TYPES OF PRIME MOVERS :**A) Steam Engines:**

These were the first engines used but have mainly been replaced by the following two types.

B) Electric Motors

Both AC and DC motors are in use. DC type is most widely used today because it has a wide torque and speed range and is easily controlled. DC-powered rigs fall into two categories: one uses DC generators and the other, which is gaining popularity, uses AC generators along with Silicon Controlled Rectification (SCR) to produce the required DC power.

C) Internal Combustion Engine

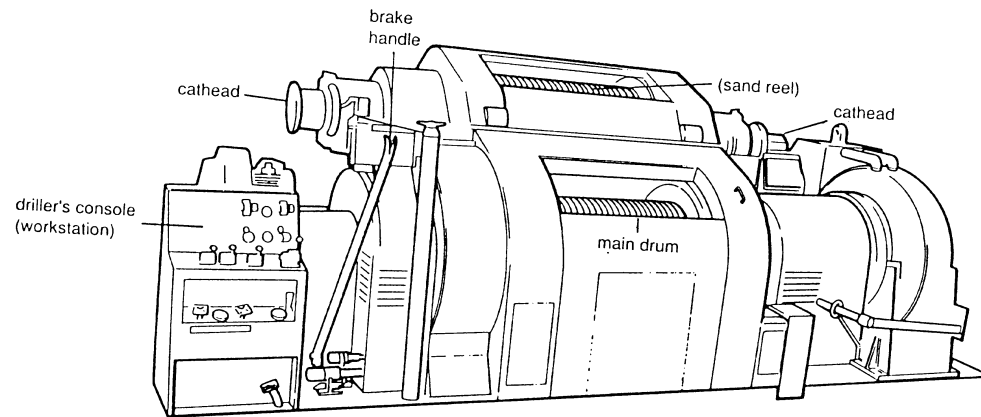
This is the most commonly used engine type due, in part, to the availability of diesel fuel. These engines are in fact inferior to both steam and electric motors. Their torque speed characteristics may be improved by the use of torque converters, but with a loss in efficiency.

12. Transmission

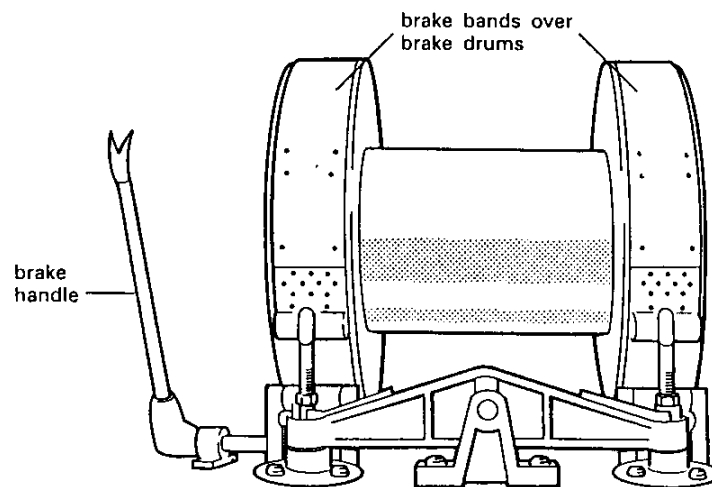
On a multi-engine rig the series of chains and clutches that connect the engines to the drilling equipment is called the transmission.

13. Draw Works

It is the control centre from which the driller operates the rig. It contains the clutches, chains, sprockets, engine throttles and other controls that enable the rig power to be diverted to the part of the operations at hand. It also houses the drum that spools the drilling line during hoisting operations and allows feed-off during drilling. A brake is used by the driller to control the speed of the drum while operations. Draw Works are commonly designated by horse power and depth rating. (Figures 12&13)



Draw works

Figure 12

Brake

Figure 13

14. Drilling Line

This line affords a means of handling the loads suspended from the hook during all drilling operations. The wire line most commonly used is the 6×19 , Seal construction, fibre core, plow steel cable. Where dictated by high load requirements, premium grade lines with an independent wire rope centre are used.

The drilling line runs from the main drum up to the crown blocks and down to the travelling blocks. The line is slung several times around the blocks. From the crown blocks the line goes down to the drill floor where it is attached to the anchor. This section of the line is known as the “dead line” since it is stationary. (Figure 09)

15. Rotary Table

This performs two functions:

1. It transmits the rotation to the drill string by turning the kelly joint.
2. It suspends the drill string weight during connections and trips.

Rotary table is usually driven by a chain from the drawworks on mechanical rigs and by its own motor on electrically driven rigs. Some are capable of speed of up to 400 RPM.

A rotary table is defined by the size of its central opening; the largest being 37½ inches. This opening is fitted with a master bushing which is split into two parts.

(Figure 14)

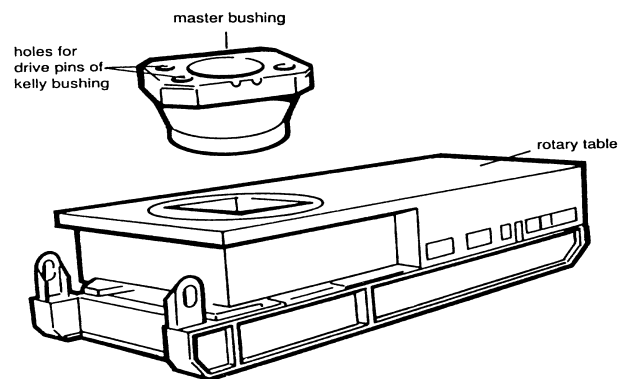


Figure 14

16. Kelly

This is the topmost joint in the drill string and is 40-45 feet in length. It is commonly square or hexagonal. The kelly passes through the rotary table and transmits the table rotation to the drill string via the kelly bushing. (Figure 15)

17. Kelly Bushing

This engages with master bushing either by having a square lower section or by four pins fitted into holes around the central opening. This transmits the rotations to the kelly. (Figure 15)

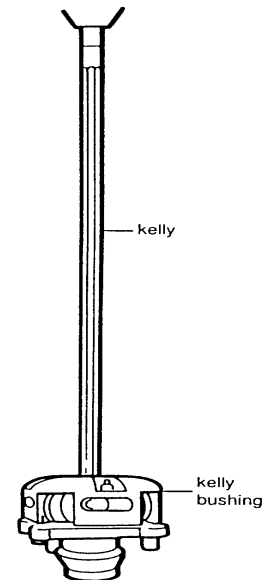


Figure 15

18. Master Bushings

Through the master bushings, the rotary table transmits rotary motion to the kelly drive bushings and the kelly. They are also the connecting link between the rotary table and the slips which support the pipe during trips.

18. Swivel

The swivel supports the drill string and allows rotation at the same time. It also allows the passage of drilling fluid from the rotary hose into the drill string. The swivel performs a very tough job supporting a load that can be measured in hundreds of tons. This string could also be rotating at 200 or more revolutions per minute. Abrasive drilling fluids are often pumped through it at the rate of perhaps a thousand gallons a minute at a pressures that can exceed 3,000 psi.

The swivel is hung from the hook by the swivel bail and is connected to the rotary hose by the goose neck. Inside the housing just below the goose neck is the wash pipe. This is made of the strongest material known to the industry. The wash pipe is stationary and is joined to the rotating swivel stem. Special packing to seal this rotating joint is contained in the stuffing box. The bearings run in an oil bath. (Figure 16)

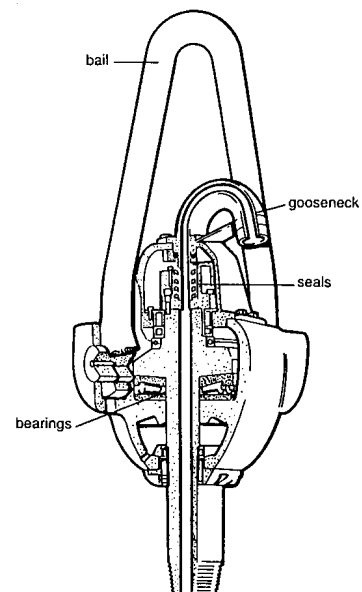


Figure 16

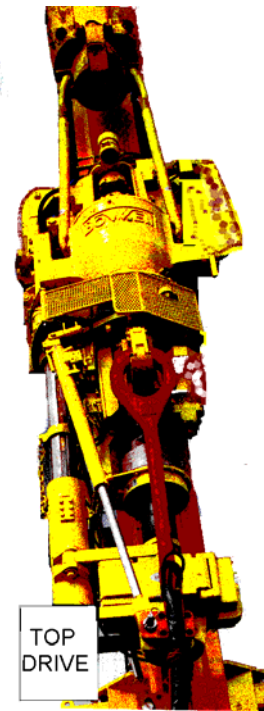
19. Top drive

This is a specially designed electric or hydraulic motor installed on the drill lines that replaced kelly and kelly bushing and it rotates the string as well.

Using the top drive enables drilling to be carried out stand by stand instead of joint by joint. This reduces the number of connections to be made while drilling.

(Figure 17)

Unlike the kelly, Top drive is not removed during trips.



20. Heave (Motion) Compensation

Heave Compensators are used on semisubmersible and float ship rigs. The two basic types of motion compensators are:

- 1st. Drill string compensator
- 2nd. Riser and guideline tensioner.

1st. Drill string Compensator:

The drill string motion Compensator system is designed to nullify the effects of rig heave on the drill string or other hook-supported equipment. (Figure 18)

Mounted between the hook and travelling block, the compensator is connected to deck mounted air pressure vessels via a hose loop and standpipe and is controlled and monitored from the driller's control console.

While drilling, the drill string compensator controls the weight on the bit. The driller lowers the travelling block to account for drill-off and to maintain the compensator cylinder within its stroke capacity while the drill string compensator automatically maintains the selected bit weight.

As the rig heaves upward, the compensator cylinders are retracted and the hook moves downward to maintain the selected loads.

Actually, the hook remains fixed relative to the seabed; the rig and compensator move, producing relative motion between the hook and rig.

The motion of both the kelly and drill string is relative to the rotary table.

2nd. Riser and Guideline Tensioners

The marine riser is essentially a conduit, but its main purpose is to maintain contact with and give access to the borehole when drilling. (Figure 18)

Riser tensioners provide tension to the marine riser pipe below the telescopic joint by a system of wires joined via sheaves to a series of pneumatic cylinders.

Its purpose is to maintain the riser in tension at all times regardless of the heaving of the rig.

It is common practice to install four or six tensioners, each with a load rating of around 60,000 lb.

Compensation for vertical movement several times the length of the stroke of the pistons is possible, due to multiple cable turns around the pistons.

Guideline tensioners operate on the same principle as the riser tensioners.

Their purpose is to maintain the correct tension in the guidelines between the rig and the guide base (which sits on the seafloor), regardless of the heaving of the rig.

The guideline tensioner is designed to deal with tensions of less than 10,000 lb; therefore, wires, cylinders and other components are smaller than those used in the riser tensioner system.

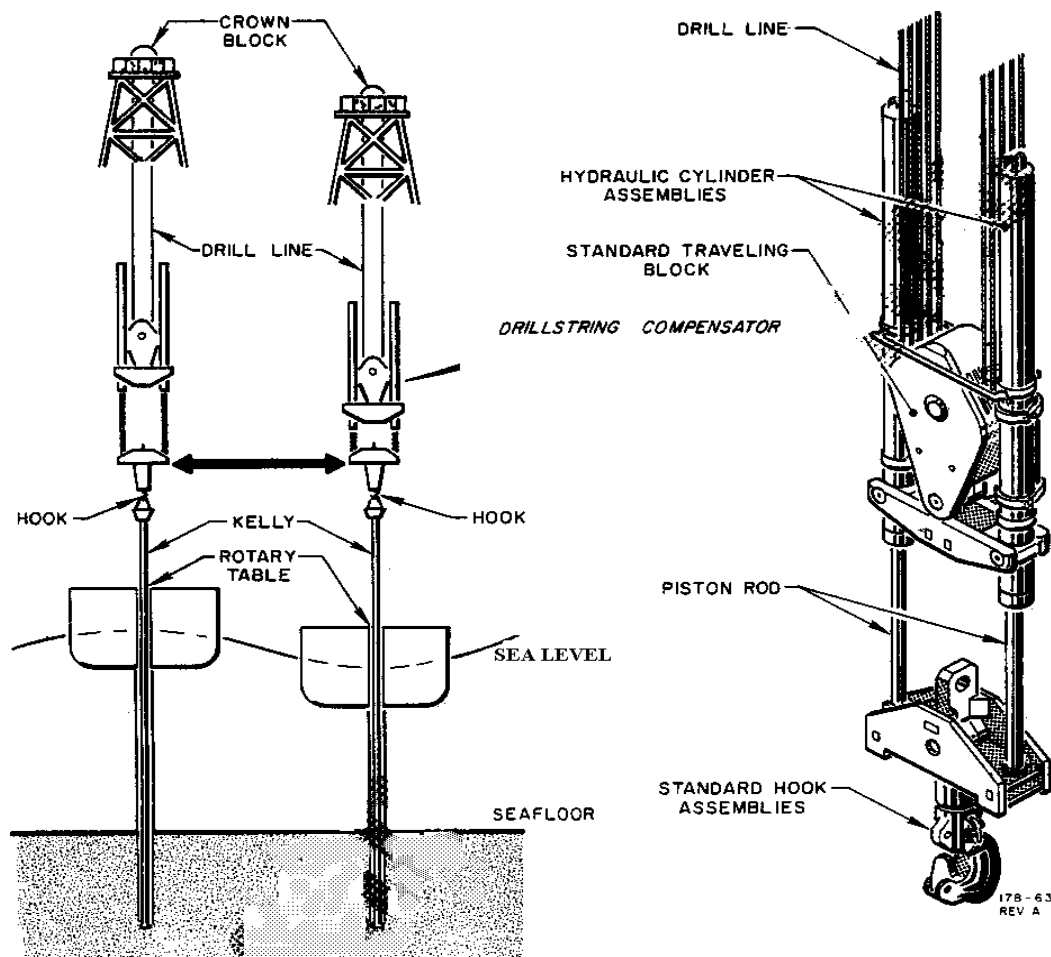


Figure 18

21. Drill String

This term includes all the components used to drill below the kelly or top drive; and it can include the following components:-

a) Drill Pipe & Tool Joints

The drill pipe furnishes the necessary length for the drill string and serves as a conduit for the drilling fluid. The drill pipe lengths (joints) are hollow seamless tubes where the tool joints (connections) are separate components and are attached to the pipe at both ends to complete the manufacture of one joint. Tool joints are of thicker outer diameter to withstand the torque applied by tongs to tighten the connection. The drill pipe joints are normally made in approximately 30 ft/9.5m lengths.

b) Heavy weight drill pipe (HWDP)

This is the same as a drill pipe but with a smaller inner diameter and longer tool joints. Because of its wall thickness, its pound-per-foot weight is greater than an ordinary drill pipe.

Heavy weight drill pipe is inserted as a section between the drill pipe section up and the lower drill collars section to serve as a transition section between the two of them, this gives the drill string the required elasticity.

c) Thread Protectors

These are either made of metal or plastic and fit on both ends of a threaded pipe (box and pin ends) to protect the threads from corrosion and mechanical damage during storage or transportation. Obviously, they must be removed before use.

d) Drill Collars

These are heavy walled, spiral and large outer diameter steel tubes. Their function is to supply the desired weight on bit and to allow the lighter drill pipe to remain in tension. The spiral grooves are to minimize the surface of contact between hole and pipe reducing the risk of getting stuck. This also helps the drilling fluid to flow up the annulus in case of tight hole.

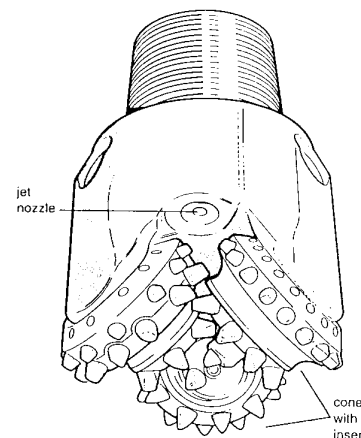
e) Rotary Bits

These may be classified into three general types :

1. **Drag Bits:-** these have no moving parts but drill by the shovelling action of their blade on the formation.

2. **Roller Bits:-** first designed by Howard R. Hughes in 1909. These may have originated from one to numerous individual rotating cones.

Three cone bits (Tri-Cone) are the most widely used in the oil field. The length and spacing of the teeth depend on the type of formation that the bit is designed to drill.



Hard formation bits may have tungsten carbide “inserts” instead of teeth. Various types of bearings are in use. Specially designed jet nozzles are set on the bit to direct the drilling fluid to produce a high velocity fluid stress on the bottom of the hole. So called conventional bits were forerunners of roller bits but were open-ended; i.e. without jets.

3. Diamond Bits:- These are designed to drill by the scraping action of diamonds set in a steel matrix. This type of bits is normally used in hard formations where long bit life and the subsequent reduction in trip time are desirable. (Fig 19)

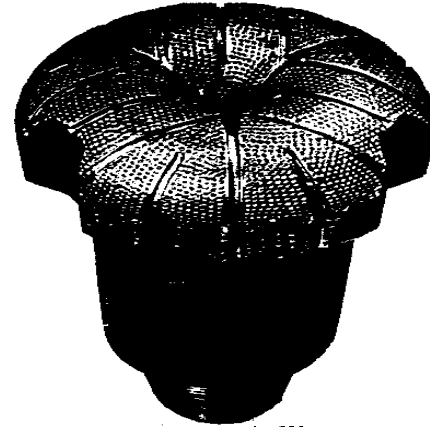


Figure 19

f) Stabilizers

These are run between the drill collars and are of a blade type construction. Drilling fluid can pass freely between the blades while the outer edge of the blades contacts the wall of the hole and holds the drill collars firmly centered in the hole. They do exactly as their name implies, they provide stability to the bit and collars. This is important as it improves bit life, in addition to keeping the direction of the hole under control. (Figure 20)

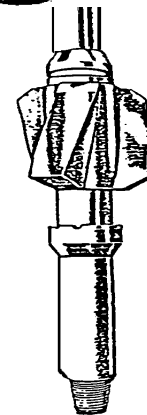


Figure 20

g) Reamers

These usually have the same diameter as the bit and are run a little distance above it. As the bit wears out it tends to decrease in diameter and consequently start drilling a smaller hole. The reamers' function is to cut the hole out to full size behind the bit.

h) Under-reamers

Used for drilling or opening out a hole below a restriction such as imposed by the blow-out preventer assembly. They are run above a conventional roller bit having their cones on collapsible arms, enabling it to pass through a narrow opening. When required, the arms can be opened, usually by the drilling fluid pressure, and a larger hole is thus drilled. (Figure21)

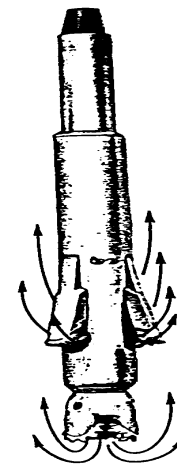
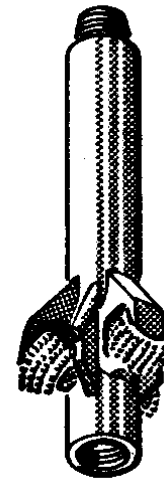


Figure 21

i) Hole Openers

These are run above a conventional roller bit and are used for drilling large diameter holes. They have replaceable cutters and serve the same function as an underreamer except they are not collapsible and can only be used when there is no restriction smaller than the hole size they drill. (Figure 22)

**j) Jars**

Jars are fitted into the drill string and are used in the event of the drill string becoming stuck. They provide upward or downward jarring blows that help freeing the string. Jars use different mechanisms including hydraulic and mechanical.

k) Monel

This is a non-magnetic drill collar used to contain the magnetic survey tools, the monel is made of special non magnetic alloy that does not affect the reading of the survey tools that determine the hole deviation depending on the deflection from the magnetic deflection of the earth sphere.

Figure 22**l) Subs**

A sub refers to any short Length of pipe, collar or casing that is made to perform a specific job. The most common types of subs you can find on rigsite are the following:

a. Crossover Sub:

A crossover sub is designed with different threaded ends for changes between different sizes and types of drill pipe or collars.

b. Bit Sub:

This sub is used to save the thread of the bit from excessive break out such as to change nozzles or BHA, So the break out of the bit is usually done at the connection between the sub and the upper collar pipe. The sub is ended with a box on both ends so that pipe and collars are always run pin down.

c. Shock sub:

This is run behind the bit with a steel spring or rubber packing to absorb the impact of the bit bouncing on hard formations and prevent damaging the rest of the drill string.

d. Bumper Sub:

This is a free telescopic sub with 6-8 ft closure. Its purpose is to absorb the effects of heave on a floating rig. and not transfer it to the bit, these are now largely replaced by the "motion compensator" which is a hydraulic device attached to the travelling block so that the entire drill string remains stationary as the rig heaves.

e. Bent sub:

This is a non-straight sub designated with different bending angles, it is fitted in the deviating bottom hole assembly above the mud motor to drill deviated holes. The angle of bending is selected according to the inclination building rate and the length of the interval to be drilled with this sub.

f. Float valve:

This is a small mechanical one way valve inserted inside the bit sub, the valve allows mud to flow in one direction from the string to the annulus, This valve is usually used while drilling the surface hole sections, the penetration rate is usually fast causing the annulus becomes loaded with cuttings, a differential pressure takes place between the annulus and the string, once pumps are shut-off, the valve is mechanically closed preventing any back flow to occur .

22. Casing head

Often called a casing hanger and is of multi purpose :-

- To provide a support point to suspend casing strings prior to being cemented into position.
- Used to provide a coupling between the various casing strings and the BOP stack.
- Having locked the casing with cement, the hanger then provides a seal between other casing strings and the annulus. A standard casing head is fixed to the first casing string and thereafter provides for up to three subsequent casing strings.

23. MUD PUMPS (Slush Pumps)

Two or three pumps are usually found on rig site, their function is to circulate the drilling fluid at the required pressure and volume. The type of pump used is a reciprocating piston pump. Pump design varies but the basic features are common Pumps may be classified on four features :-

A. Number of Cylinders:

Normally pumps have either two or three cylinders and are known as Duplex and Triplex respectively.

B. Pumping Action:

1.Double-acting Pumps - This means that both sides of the piston are used for pumping i.e. the piston is filling one side of the cylinder while fluid is being discharged on the other side. Usually Duplex pumps are double-acting. This type of pump can be easily recognised by a valve systems at both ends of the cylinder.

2. Single-acting Pumps - On these only one side of the piston is used for pumping, that is, the cylinder is then filling or discharging. Triplex pumps are usually single-acting recognizable by having a valve system at one end only.

C. Piston Stroke:-

This obviously is related to the output of the pump. It is fixed and can not be changed. The longer the stroke of the piston, the greater the pump output.

D. Cylinder diameter (Liner size): -

Each cylinder is equipped with a removable sleeve or liner. A pump, although of fixed stroke length, has a whole range interchangeable liners of different diameter available, allowing for different pressure/volume ranges with changing hole conditions. Usually, the smaller the liner diameter, the smaller the volume pumped on each stroke but as the liner walls are thicker, more pressure is available.

There are usually two to three pumps on a drilling rig. They are always of the positive displacement type. In other words plunger pumps rather like a bicycle pump.

PUMP TYPES:

**duplex, double-acting, or *triplex, single-acting*

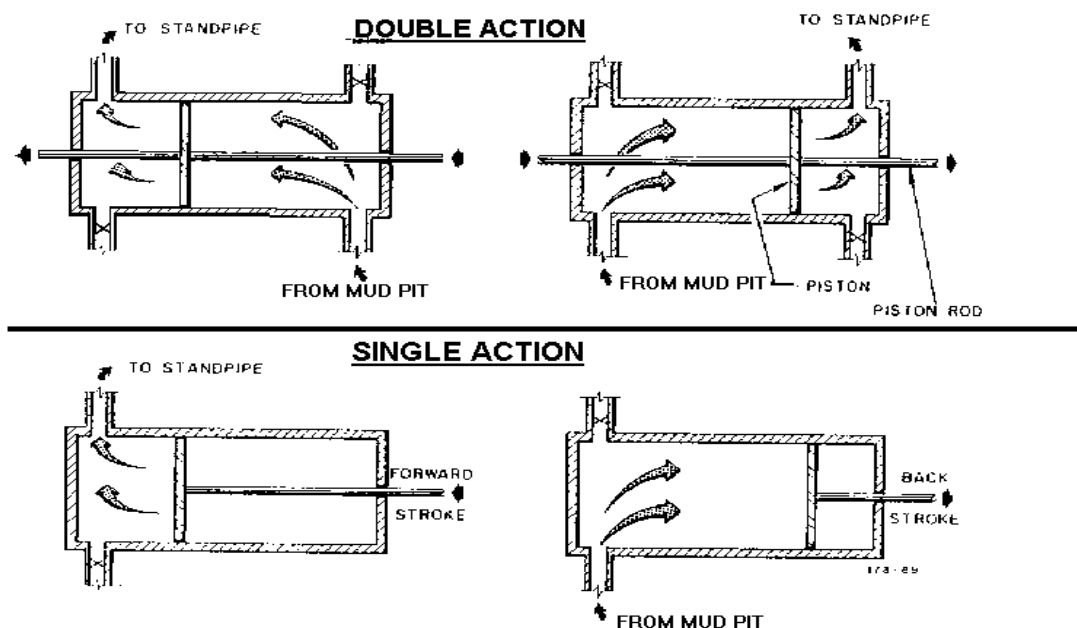
A **duplex pump** has two cylinders. Each cylinder has two suction and two discharge valves. As the piston moves through the cylinder it is discharging mud in front at the same time as mud is filling the cylinder behind.

A **triplex pump** has three cylinders with each cylinder having only one suction and one discharge valve. The cylinder is filled as the piston moves back and is discharged as the piston moves forward.

For one complete cycle of each piston a triplex pump discharges one cylinder full of mud. In a duplex pump however, because it is double acting, two cylinder volumes are discharged for every cycle of each piston.

(Figure 23) shows the pump action for each type.

Pumps are commonly rated on the horse power they transmit. Pistons are sometimes known as swabs. The discharge of the pump is fitted with a pulsation dampener and



connected to the stand pipe and rotary hose (kelly hose), through the mud line via the mud line manifold or standpipe manifold.

24. Kelly Line-Rotary Hose (Mud Hose)

This connects the standpipe to the goose neck and is flexible but strong enough to hold high pressures. These hoses may be pressure rated up to 12,000 psi.

25. Shale Shaker

This is a vibrating screen used to separate the drilled solids from the drilling fluid. The screen is mounted on a spring or rubber supported chassis, which is vibrated by means of an eccentric rotating shaft. Screens of different mesh size are available. Mesh sizes being measured by the number of openings per square inch. The screens are sometimes mounted as a pair, using screens of different sizes.

In double deck Shaker; mud returning from the well core comes down the flowline and into a surge tank; sometimes known as the **possum belly** or shaker header box; this allows a smooth flow of mud onto the screens. The shakers are usually situated over a sand trap, which is a narrow pit with sloping sides terminating in a valve, it is used to trap fine sand that may pass through the shaker screens, this pit must be dumped out periodically.

26. Desanders and Desilters

These devices remove particles from mud, which were not removed by the shakers or the sand trap. This separation is accomplished by utilising centrifugal force. The equipment is essentially a series of cones mounted on a manifold, mud is pumped into the manifold and enters the cone. The mud swirls round the inside of each cone, this rotating action causes the lighter fluids to come to one centre and rise out of a hole in the top, whereas the heavier soils go to the outside of the cone and sink down it and out of an opening in the bottom. These units are operated at low pressure (30-40 psi) but can handle high volumes, typically 250 gallons per minute per cone. The difference between desanders and desilters is mainly in the size of the cones. The smaller the cones the smaller the particles that it separates.

27. Degassers

These separate the gas that may be trapped in the drilling fluid. The principle of operation is essentially the same even though the design varies. The mud is either passed over a series of baffles or caused to swirl round in a bowl; both actions cause the mud to break up resulting in the greatest surface area possible for the gas to break out. In the swirling action the mud is spread very thinly over a surface. In addition to the increased surface area, some degassers apply a slight vacuum, this aids in the separation as the gas or air bubbles expand and break out of the fluid more easily.

28. Mud Pits

After drilling fluid has been processed by the solids control equipment; it passes into the return pit, that is connected sometimes by other pits to the suction pit. The suction pit is directly connected to the pumps allowing the mud to circulate through this

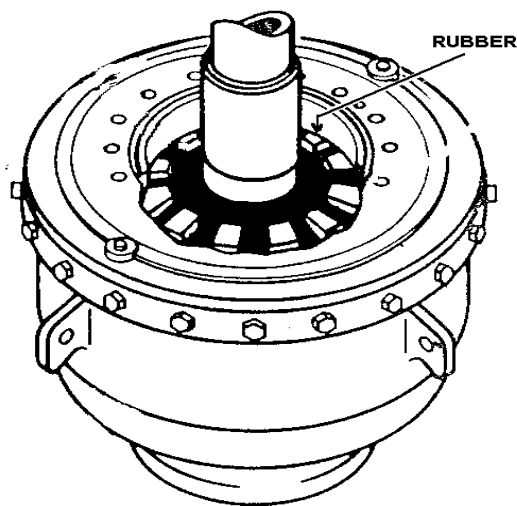
system. Between the return and suction pits the mud is constantly agitated by electric paddle mixers and mud guns.

Chemicals are added to the mud via special hoppers. The suction pit may also contain a small (typically 50 bbls) slug pit used to mix special heavy mud that may be needed when tripping or to mix other small specific volumes. The pits in use are referred to as “**Active Pits**”. All pits are equipped with valves so that their contents may be dumped or transferred easily in-between them.

29. BOP's (Blow-Out Preventers)

The main function of the blow-out preventers is to furnish a means of closing-off the annular space between the drill pipe and casing. Most preventers are either hydraulically or pneumatically controlled with manual operation available as a safety precaution. Blow-out preventers are rated according to their working pressure and their inner diameter. There are many design variations of BOP's; however, they fall essentially into two categories :

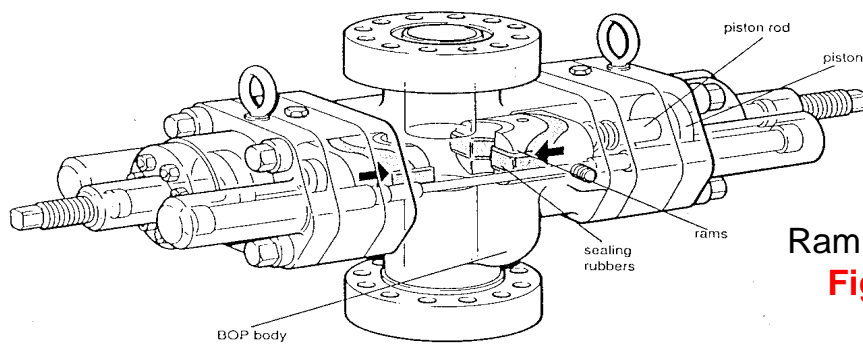
A) Annular Preventers:- This type seal by closing a circular packing element around the drill pipe; this element is made of rubber one most types will also seal the annulus with virtually anything or nothing in the bore. (Figure 24)



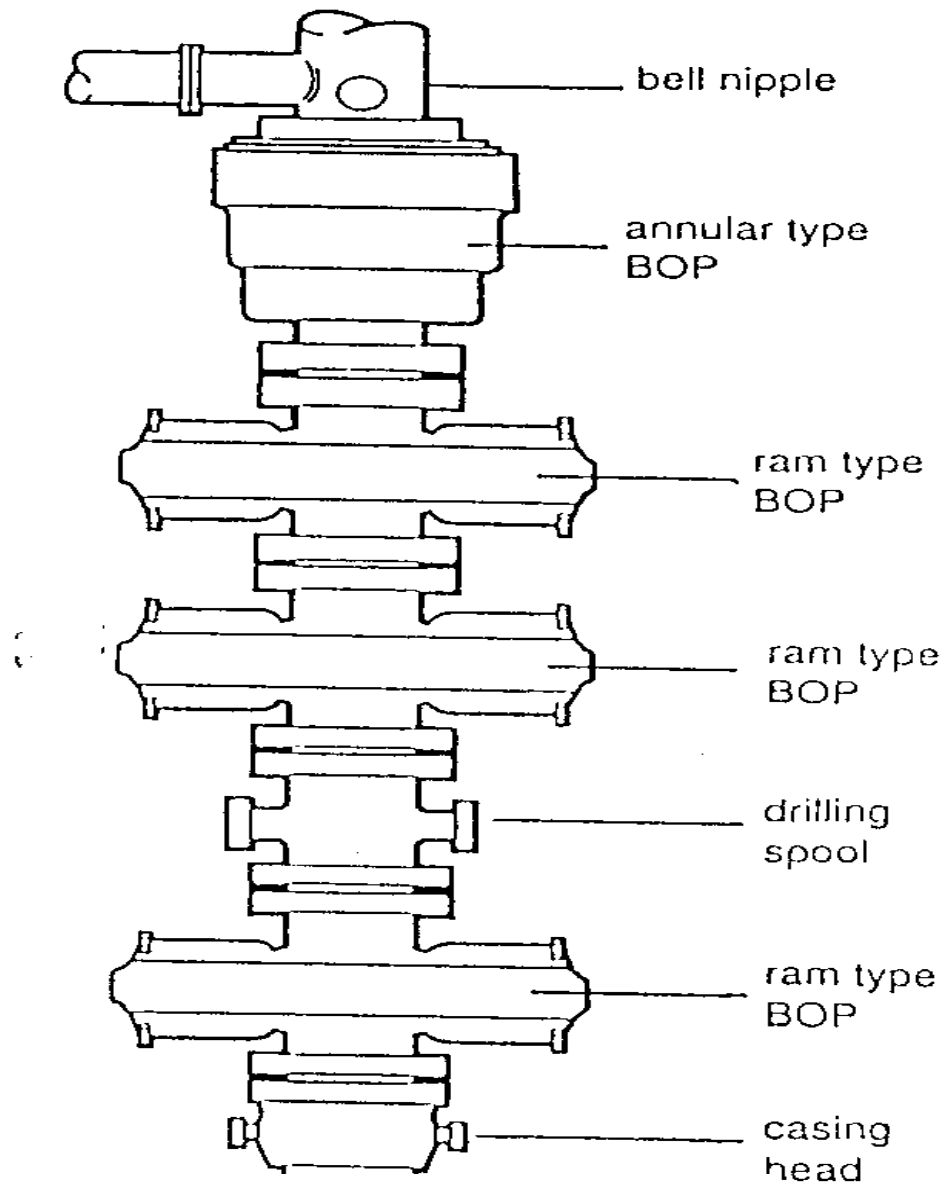
B) Ram Preventers:- These derive their name from the hydraulic cylinders and ram shafts that move the two sealing ram blocks. (Figure 25)

Unlike annular preventers, this type will only seal around a specific pipe size; to accommodate different pipe sizes the ram elements are changeable.

A set of rams and annual preventers, when assembled, is known as the **Blow-Out Preventer Stack**; commonly referred to as the stack or BOP's (Figure 26).



Ram Type BOP
Figure 25



Example of BOP Stack Arrangement

Figure 26

11. RIG PERSONNEL

- **Company Man or Company Representative:**

The operator representative usually a drilling engineer employed by the oil company engaged in drilling.

- **Tool Pusher:**

A drilling foreman or rig superintendent.

- **Driller :**

Employee in charge of the “brake” responsible for making hole as quickly as possible.

- **Assistant Driller:**

Assists driller in “making hole” and general jobs around the rig.

- **Derrick Man:**

Responsible for stacking pipe in derrick during trips. Operates from monkey board attached by safety harness. Assist mud engineer to mix mud.

- **Roughnecks/ Floor hands:**

General workers under supervision of the driller.

- **Rig Mechanic :**

Keeps the rig running smoothly. Controls maintenance of rig.

- **Motorman Rig Electrician Rig Welder:**

Keep the motors running.

- **Mud Engineer:**

Controls properties of drilling fluid within limits specified by operator.

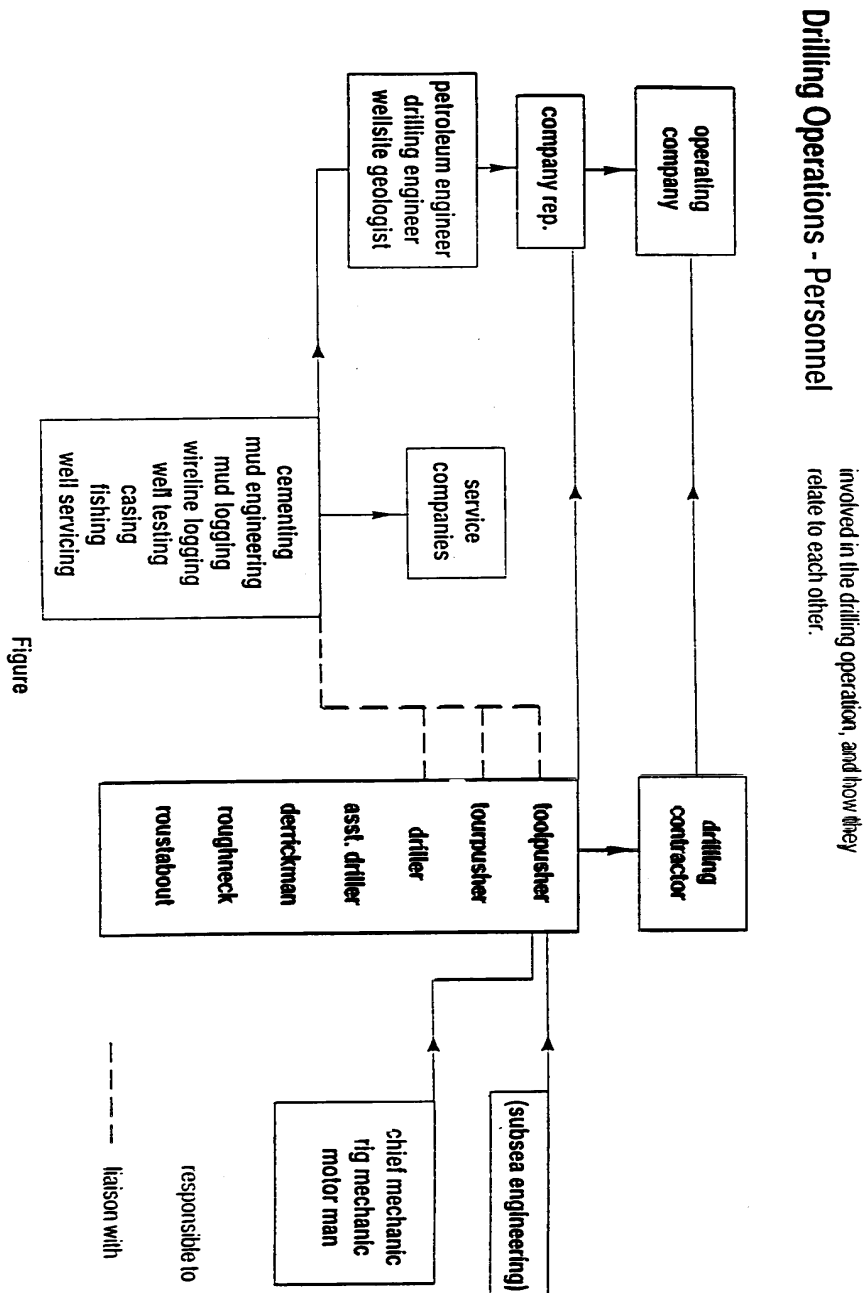
Mud Loggers :

Produce mud log of the well. Responsible for detecting changes in volume of surface mud, changes of drilling parameters and the presence of hydrocarbons.

◇ **Offshore Personnel**

- **Captain :**

Responsible for the rig as a marine vessel. He will hold a masters certificate, and is in command during rig moves.



- **Crane Operators:**

Responsible for loading and unloading of supply boats. Usually doubles as a roustabout supervisor.

- **Barge Engineers:**

Responsible for the vessels stability and rig move.

- **Radio Operator**

O p e r a t e s r a d i o t o c o m m u n i c a t e r i g t o t o w n .

The relationships between all of the previous mentioned personnel can be explained by using a simple organization chart. On the chart on the next page, the solid lines show lines of responsibility. The broken lines show where there is liaison between the companies or departments.

It is realised that this organization chart is a hypothetical one, actual company organisation may vary slightly from this.

The services provided by the service companies which are listed in the chart will be covered through the rest of the units.

List of Common Drilling Terms

Abandon	: To cease producing oil or gas from a well.
Abnormal Pressure	:Pressure exerted by a formation exceeding normal pressure for any given depth.
Acidize	:To inject Hcl into a calcareous formation under pressure, that causes, enlargement of fissures and improvement of permeability characteristics.
Annular BOP	:A large valve installed above the ram preventers.
Annular Space	:The space between drill string and casing or open hole.
API	:American petroleum Institute; founded in 1920, this organisation aims for standardisation in the oil field.
Back off	:To unscrew one threaded section from another as with pipe.
Barite	:Ba SO ₄ , a mineral used to weight up drilling fluid.
Barrel	:42 US. Gallon = 158.97 litres 1m ³ = 6.2897 bbls.
Basket Sub	:Fishing accessory run above a bit or mill to recover small pieces of junk.
Bit breaker	:Device for breaking out the bit from the string.
Blow-out Preventer BOP's	:Equipment installed to prevent the uncontrolled escape of gas oil or salt water from the well.
Breakout	:To unscrew one section of pipe from another generally during pulling of pipe. The tongs are used in this operation.
Calibre Log	:A record of the diameter of the wellbore indicating washout or enlargements due to casings.
Cap a well	:To control a blow-out by placing a very strong valve on the well bore.

Casing shoe	:A short heavy hollow cylindrical steel- concrete section with a rounded bottom placed on the end of the casing shoe. Also called a guide shoe.
Cathead	:A spool- shaped statement on each end of the draw works used for hoisting, breaking and tightening around the drill floor.
Catline	:A thin wire line used for lifting heavy equipment around the rig, powered by the cathead.
Cellar	:A pit, beneath the drill floor, to give additional clearance between floor and wellhead to accommodate the BOP's and to drain the area. To "jet the cellar" is to drain this pit.
Cement bond survey	:An acoustic or sonic logging method recording the quality of the bond between the casing and well bore.
Choke Manifold	:The arrangement of piping and chokes through that the drilling mud is circulated when the BOP's are closed.
Christmas Tree	:The control valves, pressure gauges and chokes assembled at the top of a well to control oil/gas flow.
Deadline	:The drilling line from crown-block Sheave to the anchor, that does not move.
Deviation	:The inclination of the wellbore From the vertical, in degrees.
Doghouse	:A small enclosure on the rig floor used to house driller, records and equipment.
Drilling break	:Sudden increase or decrease in penetration rate.
Drill out	:To remove residual cement with bit.
Dry hole	:A well that has no hydrocarbons or has uneconomic quantity of them..
Elevators	:A set of clamps that grip a stand, or column of casing, tubing, drill pipe or sucker rods so that the stand can be raised or lowered into the hole.
External Upset	:An extra- thick wall at the threaded end of a drill pipe or tubing. it has a thicker diameter at each end.
Fast Line	:The end the drilling line that is affixed to the reel of the draw works, that travels faster than any other part of the line.
Fingerboard	:A rack that supports the tops of the stands in the derrick.
Fish	:An object left in the well that need be recovered.

Fracturing	:A method to stimulate production from a poorly permeable zone by pressuring open the fissures jacking them open with beads or such like, then releasing this pressure.
Gas cut mud	:A drilling mud with entrained formation gas, causing reduced weight.
Joint	:A single length of drill pipe, casing or drill collar.
Kelly saver sub	:A short sub placed between kelly and drill pipe to save excessive wear on the kelly threads.
Kelly spinner	:A pneumatically operated device mound on the top of the kelly that turns the kelly. useful in making up pipe.
Latch on	:To attach the elevators to a section of pipe to pull it, or run it, into hole.
Monkeyboard	: A platform on derrick from which the derrickman works while tripping.
Mouse-hole	:An opening in the rig floor, pipe lined, that singles are placed in before making up.
Mudman	:The mud engineer.
Nipple up	:To assemble the BOP stack onto the well.
Perforate	:To pierce the casing and cement for the purpose of allowing formation fluids to enter the production piping.
Pull out	:To trip string out of the hole.
Rat hole	:Either a line hole in the rig floor on that the kelly is kept during trips, or a hole of smaller diameter drilled at the bottom of the main hole.
Round trip	:To trip out, then into the hole.
Run in	:To trip pipe into the hole.
Sheave	:A grooved pulley.
Sidetrack	:To drill around a blocked well bore by kicking off a new hole at an angle to the original.
Slip and Cut drilling line	:To remove worn fast line, and slip more line in from the anchor point so moving the dead line around.
Stabbing board	:A temporary platform erected in the derrick for use while casing.
Stand	:The connected joints of pipe racked in the derrick.
Stuck pipe	:Drill string, casing or tubing that has become immovable in the hole.

Sub	:A short length of pipe, threaded at each end, used to adapt different parts of the drill string that otherwise would not connect, or else to perform a specialist function e.g. junk sub, kelly saver sub.
T.D.	:Abbreviation of total depth - the end of the well.
Tight hole	:Under gauge hole section through which it is difficult to pull the drill string. Or a well about that information is restricted.
Tongs	:The large wrenches used for making up or breaking out drill pipe.
Work Pipe	:Moving the drill string up and down in the hole whilst not rotating to prevent sticking.
Wiper trip	:A short trip up into casing then back to bottom to clean out the hole, to check for gauge, and to reduce the danger of getting stuck.

3. THE DRILLING MUD

Following is a short section on the purposes of a drilling mud. These are briefly to:

- Clean the bottom of the hole.
- Cool the bit and lubricate the drill stem.
- Transport the cuttings to the surface.
- Support the walls of the hole;
- Prevent entry of formation fluids into the well.
- Transport the bottom hole conditions to the surface.
- Transport the (MPT) Mud Pulses Telemetry to the surface.

Other purposes of the drilling fluid are to permit the detection gas, oil or water that may enter the wellbore from a formation being drilled, and to transmit power to the bit. In addition, drilling fluid is sometimes used to drive a turbodrill or downhole motor that has been placed at the bottom of the drill stem. In this case, the drilling fluid provides power to the motor so that the bit turns without engaging the rotary table.

Purposes of Mud

To clean the Bottom of the hole

A rotary bit must have a clean surface on which to work when making hole, regardless of whether it is crushing or shearing the formation. If the chips or cuttings are not swept away as they are formed the bit bogs down and eventually the drill stem cannot be turned. For the bits to regrind the chips already broken off from the hole bottom is to waste its effort, reducing the power available for making hole. The usual method of cleaning the bottom is by fluid circulation through jet nozzles in the bit. High velocity streams of fluid blast the bottom of the hole creating a turbulence that moves the chips from the face of the formation as fast as they are formed.

Fluid that is pumped back to the bit is clean drilling can be done faster with a light weight fluid than with a heavier liquid the system should also be designed to enable a large volume of liquid under high pressure to reach the bit. the proper combination of pump, drill stem nozzles and hole diameter achieves this by enabling about 50 to 60 per cent of the fluid pressure generated by the pump to reach the bit nozzles and clean the bottom of the hole.

To Cool the Bit and Lubricate the Drill Stem

The bit is pressed against the bottom of the hole very heavily. For example, drilling weight on an 8 1/2 inch bit sometimes exceeds 60,000 pounds (lb) which is about the



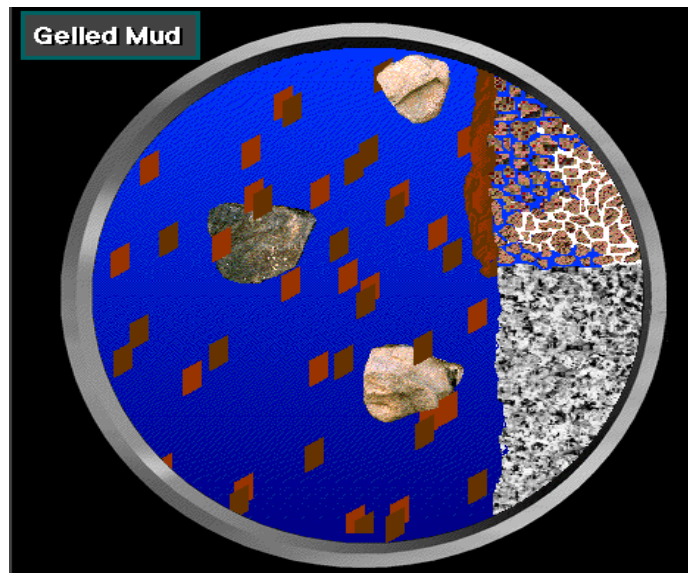
weight of a railroad freight car. A large diameter bit might require double that amount of weight. The bit may be rotated at a speed of 50 to 200 revolutions per minute (rpm). This combination of weight and speed creates heat due to friction in the bit bearings and the abrasion of the formation against the teeth or blades. Unless a bit is properly cooled, it overheats and quickly wears out. Fluid circulated around the cones and across the teeth removes the heat as fast as it is generated. Oily substances in the drilling fluid can reduce friction in the bit bearings and act as a lubricant between the drill stem and the Walls of a hole. Oil emulsion mud and oil mud are especially beneficial in this regard. Air or gas circulation is particularly efficient for cooling because the air or gas expands as it leaves the nozzles of a bit, causing a cooling effect. For this reason and because air contains no significant foreign material wear on the bit bearings is much less with this method than with mud circulation.

To transport the cuttings

The liquid, air, foam or gas circulated moves rock chips, sand or shale particles out of a well as it moves up the annulus. For a liquid, the annular velocity may range from 50 to 100 feet per minute (ft/min) in order to keep the hole clean. Circulation of 3000 ft/min is considered ample velocity in the annulus for cleaning with gas, foam or air. The solids in the liquid mud are separated from the mud at the surface by screening, settling, centrifugal action or a combination of these methods. When drilling with air, foam or gas, the solid materials are blown as dust or fine chips to a waste pit.

The viscosity of a drilling mud is defined as its *resistance to flow*. A Marsh funnel is the usual means used to measure apparent viscosity of the mud. The marsh test measures a timed rate of flow that roughly correlates with true viscosity. Funnel viscosity may be from 30 to 40 seconds (s) for low- solids muds, from 40 to 50 (s) for a high-solids muds and above 50

(s) for heavier muds. The viscosity and Gel strength (Gel strength is the ability of a mud to tend to solidify or gel when it is not in motion- when it is pumped it thins) of a drilling mud are increased by the addition of clay or bentonite. Conversely, water or chemicals can be added to reduce viscosity and gel strength. Gel strength - whether low, medium or high - can be observed from the way the mud flows and stiffens in the ditches and pits. Drilling muds are subject to wide variations but it is relatively simple to develop enough gel strength in a water-base mud to suspend cuttings and particles of normal specific gravity (weight) in the hole when circulation is stopped.



To Support the walls of the Well

A drilling fluid with the proper characteristics can support a formation that might otherwise cave into a well. This type of drilling fluid, plasters the walls of a well like a mortar. The hydrostatic pressure created by the weight of the fluid column in the hole pushes against the plastered wall to support unconsolidated or loose formations that might tend to fall or slough into the well. Hard-rock formations usually do not have this tendency to slough and can be drilled with air, gas or water instead of mud. Hydrostatic pressure (force) against the sides and bottom of a hole is caused by the weight of the fluid above that point in the well; it is determined by the unit weight or density of the fluid and the height of the column of fluid (that is, the depth). An increase in the hydrostatic pressure at any depth can be obtained by increasing the density of the fluid, a process usually accomplished by adding finely ground barite to the mud. Barite is a mineral that is 4.3 times heavier than water.

The weight of drilling mud is measured by means of a mud balance. Mud weight is commonly expressed in terms of pounds per gallon (ppg), pounds per cubic foot (pcf), kilograms per litre (Kg/Lt) or gram per cubic centimetre (g/cc) which is the same as the specific gravity. Pounds per square inch (psi) of pressure per thousand feet of head, that is, hydrostatic pressure, is also used to express mud weight. Hydrostatic pressure may be roughly estimated at about 1/2 psi for each foot of depth with mud weighing 10 ppg (75 lb/ft³). In the metric system a mud weighing 1.2 kg/litre exerts about 11.7 kPa for each metre (m) of depth; Pressure is expressed in Pascal, Kilopascals or Megapascals. Hydrostatic pressure can be calculated by using one of the following expressions:-

HYDROSTATIC PRESSURE (PSI) = depth (ft) x mud weight(ppg)x0.052, or

HYDROSTATIC PRESSURE (PSI) = depth (ft) x mud Weight(lb/ft³)x0.00695, or

HYDROSTATIC PRESSURE (MPa) = depth (m) x mud Weight(kg/Lt)x0.00980

Filter cake, the plaster-like coating formed from mud on the walls of a well, has the ability to seal the wellbore and prevent the loss of fluid. Filter cake is formed by fluid pressure against the sides of the wellbore, which causes the solids to be separated from the liquid- particularly in those areas in which there is a permeable section in the well. The force of the hydrostatic pressure literally squeezes the liquid phase of the mud (the filtrate) into the permeable zones and the solid material is left behind as a filter cake.

This filtration slows to a very low rate when a thick filter cake has been formed on the walls of a well. Finely ground clays or other substances are added to a drilling fluid to improve its wall-building quality, that is, its ability to form a filter cake. Measurement by means of a filter press of the amount of filtrate that accumulates when a mud is tested helps indicate the wall-building quality of that mud.

Certain difficulties may arise if the fluid loss of a mud becomes excessive. First the filter cake may become thick enough to reduce the diameter of the hole, thus causing tight intervals in the hole and even sticking the drill-stem. Second, muds with a high fluid loss tend to cause sloughing and caving of shale formations due to the entry of

filtrate into the formations. Third, filtrate entering the productive zones may make it difficult to complete the well.

To Prevent Entry of Formation Fluids into the Well

The pressure of gas, oil or water in formations penetrated by the bit may exceed the hydrostatic pressure of the fluid column in a well. If this happens, formation fluid enters the well unless back pressure is held on the column at the surface or heavier mud is circulated in order to obtain enough pressure at the bottom of the hole to overcome the formation pressure.

The addition of weighting materials to the mud being circulated in a well can make a mud heavy enough to hold back almost any formation pressure. When formation pressures are expected to be high, a high mud weight is needed and the pits and other equipment should be especially arranged to handle the heavy mud. A mud weight of 16 to 18 ppg (120 to 135 lb/ft³, or 1.92 to 2.16 g/cc) is considered heavy.

The special valves and fittings at the well head, called blowout preventers, are for emergency control when formation fluids enter the hole. They are used to close in the well and allow mud of a weight heavy enough to control the pressure to be circulated. Maintaining the proper mud weight and carefully controlling other mud characteristics are the best ways to prevent blowouts. Although this lesson does not deal with the technique of killing a threatened blowout, the new man on the rig should know the signs of an upcoming blowout. The first sign of a blowout is an increase in the volume of fluid returning from the hole. Also when a blowout is about to occur, mud continues to flow from the well when the pump is shut down and a volume gain in the mud pits is observed.

COMPOSITION AND NATURE OF DRILLING MUDS

Water or oil are satisfactory drilling fluids in many instances. Generally, the functions to be performed require mud properties which can not be obtained from ordinary liquids. A typical mud consists of:

- (1) A continuous phase (liquid base)
- (2) Dispersed gel-forming phase such as colloidal solids and/or emulsified/liquids which furnish the desired viscosity, thixotropy and wall cake.
- (3) Other inert dispersed solids such as weighting materials, sand and cuttings.
- (4) Various chemicals necessary to control properties within desired limits.

12. TYPES OF MUD

The most common types of the drilling mud are the following:

- 1- Fresh water mud
- 2- Calcium treated fresh water mud
- 3- Salt Saturated mud

4- Oil base mud

13. Mud Properties Terminology

The following is a brief explanation of the mud data on the ADT morning report.

Density

Density (weight) : Any accepted terminology that indicated the weight per unit volume of a drilling fluid that may be used to determine the hydrostatic pressure exerted by that fluid. It is measured in three basic ways, they are as follows : Pounds per gallon, pounds per cubic foot and specific gravity.

The effects of density are as follows : Hydrostatic pressure, pressure differential on the formation, and therefore, drilling rate, hydraulics, circulating pressure, lifting capacity and hole cleaning, flow pattern (laminar or turbulent) stability of pressured formations.

Rheology

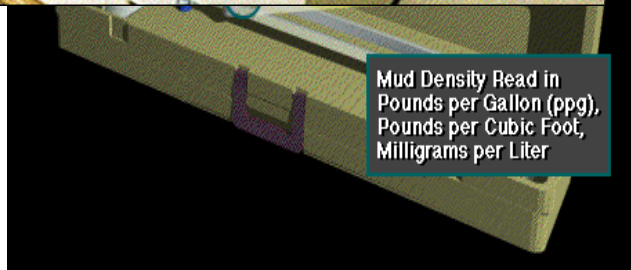
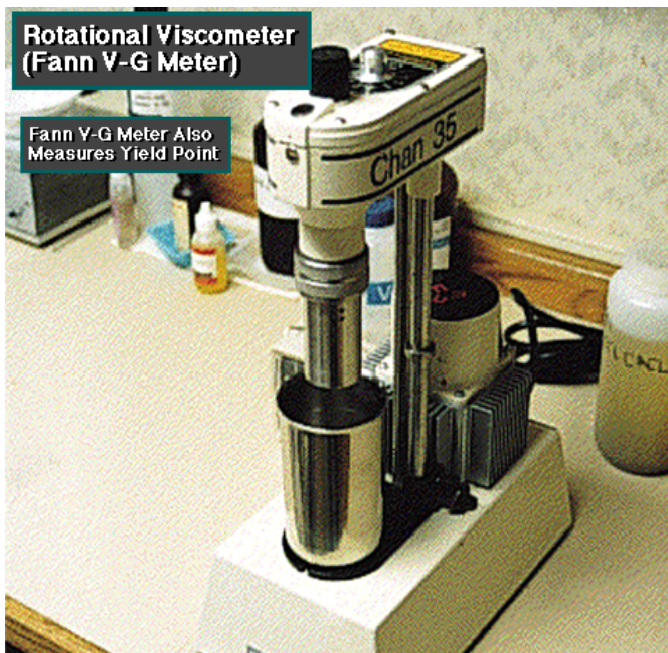
Rheology (viscosity at all shear rates) : All the characteristics that define the flow and gelation properties of a drilling fluid.

Funel Viscosity

Is a routine field measurement of the viscosity of drilling fluid are made with a marsh funnel. This measures a timed rate of flow in seconds per quart under specific gravit free fall. The values obtained are called “apparent” viscosity.

Plastic viscosity:

is that part of flow resistance in a mud caused primarily by the friction between the suspended particles and by the viscosity of the continuous liquid



phase. For practical purposes plastic viscosity depends on the concentration of solids present and the size and shape of these solid particles.

Yield point:

is a measurement under flowing conditions of the forces in the mud which cause gel structure to develop when the mud is at rest. These forces exist between the solid particles, and are the result of positive and negative electrical charges located on or near the surface of each particle. When the mud is at rest, the solid particles tend to arrange themselves in such a manner that these attractive and repulsive forces are best satisfied.

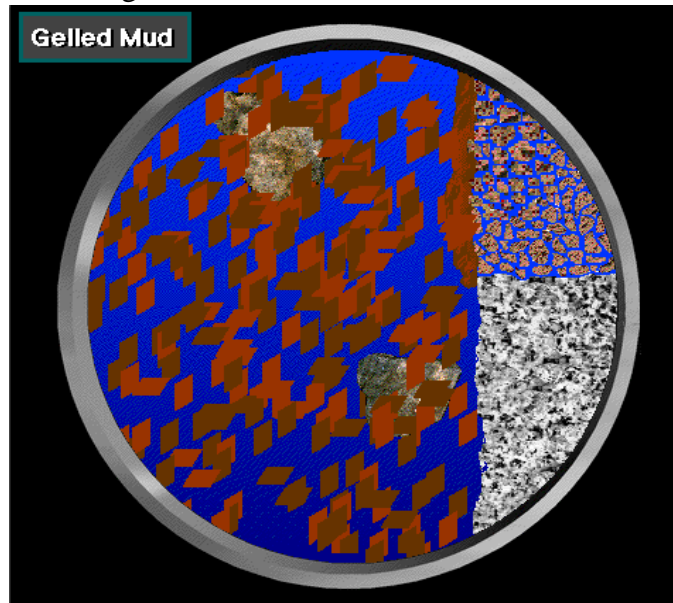
Gel strength:

is a rheological property of a drilling fluid at rest. Drilling mud has gel strength when a force is required to start the mud moving. Gel strength arises mainly from attraction between particles and from friction between solids in suspension or between the solids and the liquid around them. Gel may be progressive in that gel strength may increase continuously for a long period of time, while the gel strength of other muds may reach a near-maximum in a brief time. Gel strength is related to alkalinity; for the stronger alkalinity while acid solutions range from just below 7 for slight acidity to less than 1 for the strongest acidity.

pH :

measurement is used as an aid in determining the need for chemical control of mud as well as indicating the presence of contaminants such as cement, gypsum etc.

There are two common methods of obtaining this value. The pHydroin dispenser which provides a series of paper indicator strips that determine pH from 1 to 14. Changes in color or color identify over the range of each indicator should be sufficient to allow the operator to read to within 5 pH units. The other method is the pH meter. The meter will measure the pH within 1pH units.

**Filtration**

The filtration properties of drilling muds are a measure of the ability of the solid components of the muds to form a thin low-permeability filter cake. The lower the permeability, the thinner the filter cake and the lower the volume of filtrate from muds of comparable solids concentration. This property is dependent upon the amount and physical state of the colloidal material in the mud. It has been shown repeatedly in the

field that when the mud of sufficient colloidal content is used, drilling difficulties are minimized. In contrast, a mud low in colloids and high inert solids, deposit a thick filter cake on the walls of the hole. A thick filter cake restricts the passage of tools and allows an excessive amount of filtrate to pass into the formation, thus providing a potential cause of caving. Lack of proper walling properties may result in further trouble such as difficulty in running casing, creating a swabbing effect, which may cause the formation to cave or swab reservoir contents into the hole, and difficulty in securing a water shutoff because of channeling of cement.

HT/HP (high pressure high temperature) method of obtaining the filtration property is used to simulate down hole conditions.

Alkalinity

A dictionary description of alkalinity is water soluble chemicals that can neutralize acids. There are three tests for alkalinity which are pm, pf and mf.

Ph and **mf** is the alkalinity of the filtrate. **Pf** is the amount in milliliters of N/50 sulfuric acid required to reduce the pH of one ml of filtrate to 8.3. **Mf** is equal to the **ph** and ml of N/50 sulfuric acid required to reduce the **ph** from 8.3 to 4.3.

With the use of these tests, one can determine the type of contaminate present in the mud.

Chloride Content

It is desirable to know the salt content of muds to account for certain aspects of their performance. Filtration, suspension, viscosity and gel properties are adversely affected by salt unless the mud is specifically designed to withstand salt contamination. Salt content determination made at regular intervals may be useful in identifying salt sections or filtration of salt water into the mud system.

The salt content in the sample is expressed as parts per million chloride (ppm Cl). Multiply ppm CL x 1.65 for ppm NaCl.

Calcium

In the control and maintenance of a drilling mud, it may be desirable.

4. RIG PROCESSES

- **Drilling**
- **Tripping**
- **Stuck pipe**
- **Fishing**
- **Wireline logging**
- **Casing**

- Cement
- Setting Production Casing
- Perforating
- Testing
- Drill Stem Test (DST)
- Acidizing
- Fracturing
- Installing Christmas Tree

14. Drilling

a) Normal drilling :

operations are what the rig and crew are hired to do. Simply stated normal drilling operations are:-

1. Keeping a sharp bit on bottom, drilling as efficiently as possible.
2. Adding a new joint of pipe as the hole deepens.
3. Tripping the drill string out of the hole to put on a new bit and running it back to bottom, i.e. making a round trip.
4. Running and cementing casing large diameter steel pipe that is put into the hole at various predetermined intervals. Often however special casing crews are hired to run the casing and usually a cementing company is called on to place cement around the casing to bond it in place. The rig crew usually assists in casing and cementing operations.

To understand the sequence of the operation and to get the ball rolling, assume that the crew is ready to begin drilling the first part of the well. Firstly about 20 to 100 feet has to be drilled and lined with conductor pipe. The diameter of the conductor pipe varies but in this example assume it is 20 inches. Conductor or surface pipe can be hammer driven or a borehole made to lower the conductor into and cement the pipe in place. A casing head is fixed to the top of the conductor at the surface.

The next bit used will have to be smaller than 20 inches. Here, a 17½ inch bit is chosen. This fairly large bit is made up on the end of the first drill collar and both bit and drill collars are lowered into the conductor hole. Enough collars and drill pipe are made up and lowered in until the bit is almost to bottom.

Over the years a standard selection of bit sizes has evolved usually starting with a maximum of 36" bit followed by:- 26" - 17½" - " 12 ¼" - 8 ½" - to- 6".

Less common, but available, are a number of bit sizes below 6".

Similarly, standard casing are used. These naturally, are of slightly smaller diameter from the bore drilled in that the casing will be run. Namely:- 30", 20" 13 3/8" 9 5/8" to 7". Again smaller sizes are available but these tend to be more common in production operations.

The kelly is picked up out of the rat hole where it has been stored and is made up on the topmost joint of drill pipe sticking up out of the rotary table. This joint of pipe is suspended in the rotary table by the slips. With the kelly made up, the pump started to begin circulating drilling mud and the kelly bushing in the rotary table and rotation begins. Next, the driller gradually releases the drawworks brake and the rotating bit touches bottom and begins “making hole”. Using an instrument called the weight indicator, the driller monitors the amount on weight put on the bit, Since the kelly is about 40 feet long, after 40 feet of hole is made the driller stops the rotary, stops the pumps and raises the kelly exposing the top of the previously connected joint.

The drilling crew prepares to make the first connection. They set the slips around the joint of pipe and latch a big set of wrenches - called tongs - around the base of the kelly. A tong pull line - a length of a strong wire rope - runs from the end of the tongs over to the breakout cat-head on the drawworks. The driller engages the cat-head and it starts pulling on the line with tremendous force.

The pulling force on the tongs breaks out or loosens the threaded joint between the kelly and drill pipe. Once the joint is loosened the crew removes the tongs - and the driller engages the kelly spinner (an air-actuated device mounted permanently near the top of the kelly).The kelly spinner turns or spins the kelly so that it unscrews rapidly from the drill pipe.

The crew moves the kelly over to the mouse-hole, which is just a hole in the rig floor lined with pipe into that a joint of drill pipe is placed prior to it's begin made up in the string. The crew stabs the kelly into the box of the drill pipe and spins the kelly. The crew grabs the tongs, latches them onto the kelly and pipe and bucks up (tightens) the joint to final tightness.(each pipe size and grade has its own tightening torque range that must never be exceeded by the driller).

Next, the driller uses the drawworks to raise the kelly and attached joint out of the mouse-hole. The crew stabs the end of the new joint hanging in the rotary and the two are connected together, that is, the joint is spun up and tongs are used to make them up to final tightness. Finally, the driller lifts up the kelly and attached strings a little, the crew removes the slips and the newly added joint and kelly are lowered until the kelly bushing engages the rotary.

What has just been described is called “making connection” and can actually be carried out almost in less time than it takes to tell about it.

The pump is started, the bit is set back on bottom and another thirty or so feet are drilled, A connection is made each time the kelly is drilled down i.e. each time about thirty feet of hole is made. The kelly is normally fifteen feet longer than a joint giving room for manoeuvre. Near the surface, where the drilling is usually easy, the crew will probably make many connection whilst they are on tour.

At some predetermined depth, perhaps as shallow as a few hundred feet to as deep as several thousand feet, drilling stops,. The first part of the hole the surface hole- is only drilled deep enough to get past soft sticky formations, gravel beds, freshwater - bearing formations and so forth that lie relatively near the surface. At this point the drill string and bit are tripped out of the hole to run the casing.

(b) Directional Drilling

Usually but not always, the crew tries to drill the hole as straight as possible, but at times it is desirable to deflect the hole from vertical. The most dramatic example of this is the offshore platform. Many wells may be drilled from a single platform without having to move the rig. The technique used is called “directional drilling”.

Only the first hole drilled into the reservoir may be vertical; each subsequent well may be drilled vertically to a certain depth then kicked-off (deflected) directionally so that the bottoms of the hole ends up away from its starting point on the surface.

By using directional drilling, as many as twenty or more wells may be drilled into the reservoir from one platform. Thus directional drilling has become a routine development operation throughout the world.

Controlled directional drilling has many applications. It is used for inaccessible locations, offshore drilling from shore or sea platforms, geological corrections, relief wells, side-tracking tools lost in the hole, redrills to save surface cased hole and a portion of the open hole and bottom hole re-completion.

(c) Drilling to total depth (TD)

The final part of the hole is what the operating company hopes will be the production hole. To drill it the crew picks out the smallest bit, say one of 8 inches. This bit is tripped in, drills out the intermediate casing shoe and heads toward what everyone hopes is “*the pay zone*”, a formation capable of producing enough oil and/or gas to make it economically feasible for the operating company to complete the well. Once again, several bits will be dulled and many round trips made and soon the “formation of interest” (the pay zone; the oil sand or the formation that is supposed to contain hydrocarbons) will be penetrated by the hole. It is then time to consider whether the well contains enough oil or gas (or strong enough suggestions of) to make it worthwhile running the final production string of casing and completing the well.

15. Coring

Besides the above mentioned tests, formation core samples are sometimes taken. Two methods of obtaining cores are frequently used.

(a) Conventional coring:

An assembly called a “core barrel” is made up on the drill string with a special type of bits called “Core Head” and run to the bottom of the hole. As the core barrel is rotated, it cuts a cylindrical core a few inches in diameter that is received in a tube above the core cutting bit. There are many types of core barrel in use as the conventional, the rubber sleeved, The fibreglass, ..Etc. A complete round trip is required for each core taken.

(b) Sidewall coring

In a sidewall sampler a small explosive charge is fired to ram a small cylinder into the wall of the hole. When the tool is pulled out of the hole, the small core samples come out with the tool.

Either type of core can be examined in a laboratory and may reveal much about the nature of the reservoir.

16. Tripping

There is a number of occasions when all the drill pipe would have to be removed from the hole and then re-run again.

Imagine a well having reached a depth of say 10,000'. Then bit has become worn and needs replacing. This means that 10,000' of drill pipe must be pulled from the hole, then the old bit is replaced with a new one.

Once this is done, everything must then be lowered back into the hole until the bit is on the bottom and drilling can recommence.

The pipe would have to come out of the hole to change a worn bit, or to insert casing, or if any part of the bottom hole assembly had to be changed,etc.

This whole process is called a round trip and would take a very long time however, and time means money in the drilling industry.

To save time, the pipe is removed in lengths of three joints of pipe. Each length of three joints, which measures approximately 100', is called a stand.

This process is done in the steps below:-

Step 1

The drillpipe is suspended in the hole and the kelly is disconnected. (Using slips and tongs as before).

Step 2

The kelly is swung across the rig floor and lowered into the rat hole, then the swivel is unlatched from the travelling block hook. The rat hole is a tube rather like the mouse-hole. It provides a storage receptacle for the kelly, kelly bushings and swivel when they are not in use during the round trip.

Step 3

One of the rig crew - the derrickman, climbs to the monkey board high in the derrick. He secures himself at this working platform using a safety harness. It is his job to handle the top of the stand during the round trip.

Step 4

Elevators are latched around the drill pipe just below the tool joint. The elevators are a set of hinged clamps, which are part of the hook and travelling block assembly. They are connected to links which themselves are attached to the eyes of the hook.

Step 5

The driller can now start to pull the drill string out of the hole. As he starts to raise the string, the slips are removed by the roughnecks on the rig floor. The string is then lifted until the third tool joint is clear of the rotary table and the slips are re-set.

We now have a stand of drill pipe up in the derrick being held by the elevators, while the rest of the string is in the hole suspended from the slips.

Step 6

The next job for the roughnecks, is to disconnect the stand from the drill string. This is done using the tongs and pipe spinner. The lower end of the stand is then swung to one side of the rig floor and stood down.

Step 7

The derrickman job now is to unlatch the elevators having first secured the top of the stand with a rope. With the stand now clear, he can pull the top of the stand into the fingers of the monkey board. The stand is now racked (stored) in the derrick.

Step 8

The driller now lowers the travelling assembly, allowing the roughnecks to latch the elevators round the next tool joint ready to pull another stand.

The procedure which was just described is repeated until all the pipe is out of the hole. Depending on the depth of the hole, this could take an entire day to complete.

The drill collars and bit are the last items to come out of the hole. To unscrew the bit from the bit sub, a device called a bit breaker is placed in the rotary table.

This piece of equipment holds the bit while the tongs are used to break the connection.

We have now seen one half of a round trip, tripping out. The second half of a round trip is called tripping in and is just the reverse procedure. [See figure 27](#)

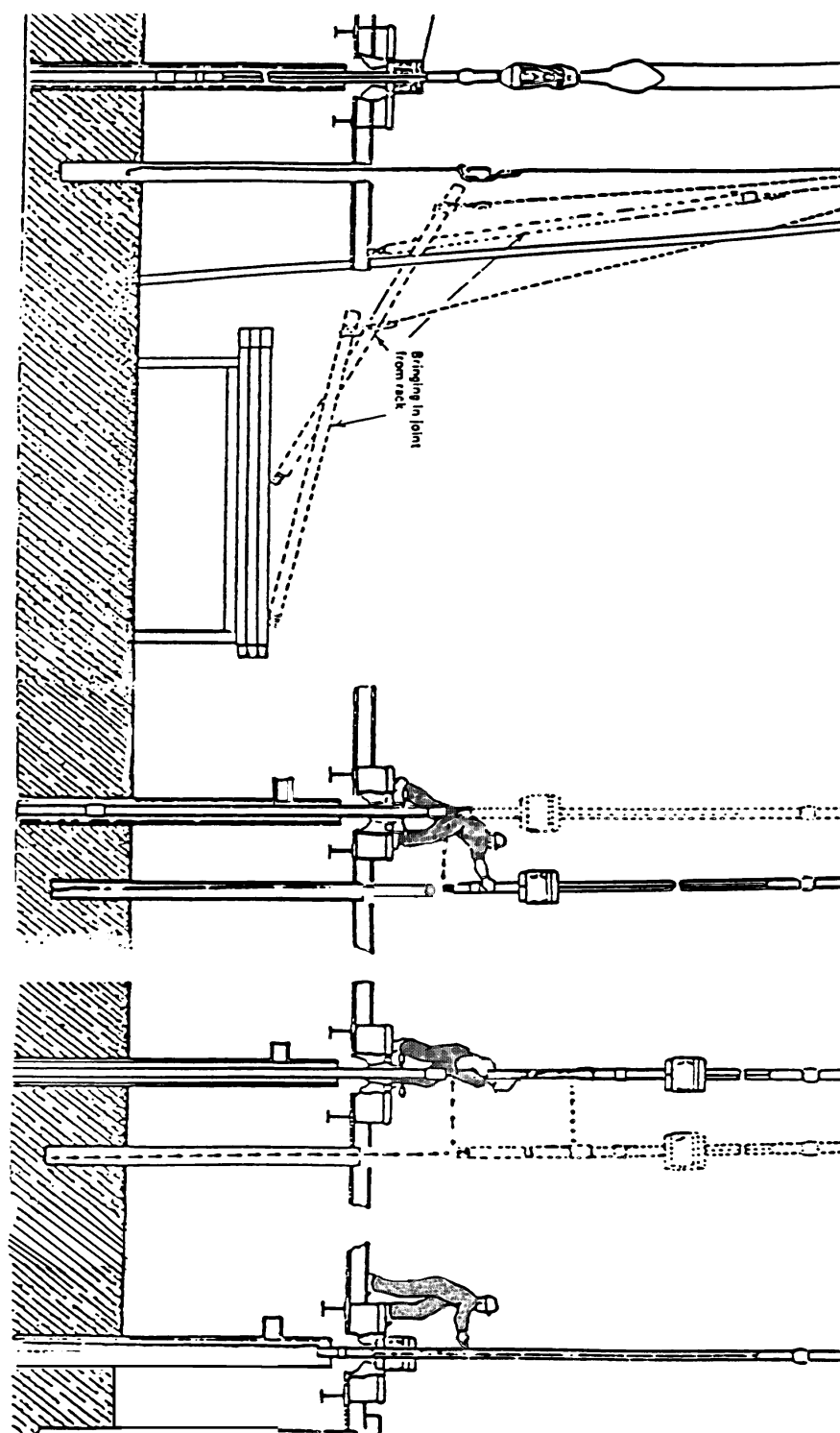


Figure 27

A sketch showing connection procedure

TRIP MONITORING

During trips the drilling crew and the mud logger should keep a close watch on the amount of mud used to fill the hole as pipe is removed, and the amount of mud received from the hole as pipe is added. This is made easy by using of the trip tank, that is a small tank showing sensitive changes in loss/gain.

- The detailed discussion of trip monitoring procedure will be covered later on as a separate important subject within the section of duties and responsibilities of the Mudlogger..

17. STUCK PIPE

A string may become stuck because of one reason or a combination of different reasons. Industry convention categorizes the causes as either **differential** or **mechanical** sticking.

1. DIFFERENTIAL STICKING

During most drilling operations, the pressure exerted by the mud column is usually kept greater than the pressure of the formation fluids to ensure a state of overcoming. In permeable formations, mud filtrate will flow from the well into the rock building up a filter cake. A pressure differential will exist across the filter cake, which is equal to the difference in the pressure of the mud column and the formation.

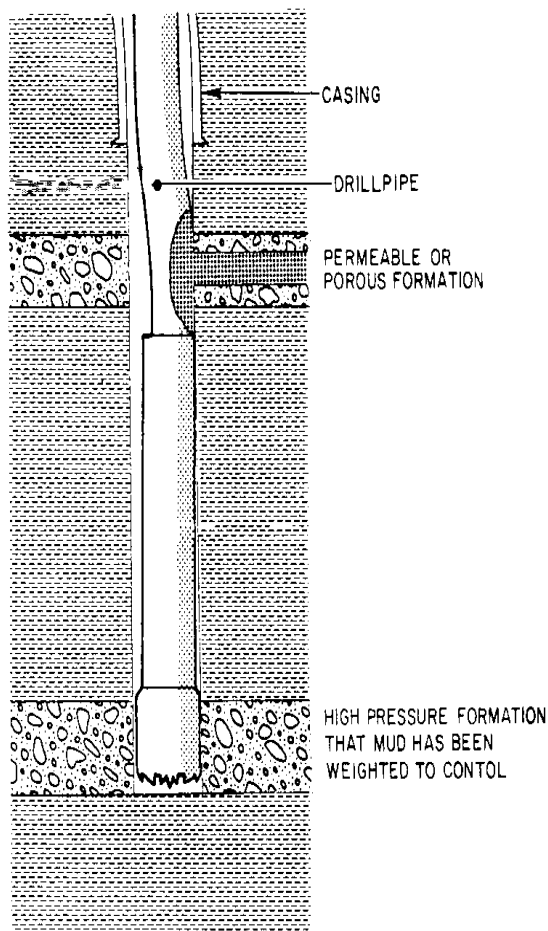
When the drill string touches the filter cake any part of the pipe which becomes embedded in the cake, will be subject to a lower pressure than the part which remains wholly in the well. If the pressure difference is high enough and acts over a sufficiently large area, the pipe may become stuck.

The force required to pull differentially stuck pipe free, depends upon:

One) The difference in pressure between the borehole and the formation. Any overbalance adds to side forces which may exist due to the deviation of the hole.

Two) The surface area of pipe embedded in the wall cake. The thicker the cake or the larger the pipe diameter, the greater this area is likely to be.

Three) The coefficient of friction between the pipe and the wall cake is a very significant factor, being directly proportional to the sticking force. It tends to increase



with time, making it harder to pull the pipe free. Different muds will have different profiles and values for the friction coefficient. Water based muds range from 0.05 to 0.25, with oil muds having a narrower range from 0.06 to 0.16.

2. MECHANICAL STICKING

Mechanical sticking results from one, or a combination, of the following:

One) *Inadequate hole cleaning*

Two) *Formation instability*

Three) *Key seating*

Four) *Running into undergauge hole*

Five) *Drilling plastic formations*

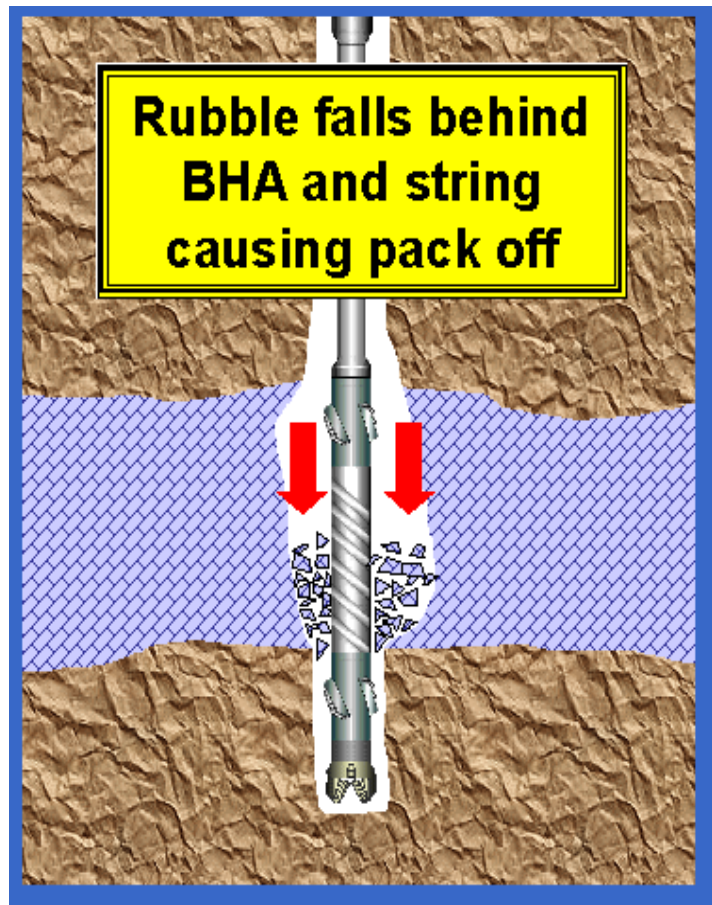
Six) *Large boulders falling into the hole*

a) *Inadequate Hole Cleaning*

If cuttings are not removed from the well, they will settle around the drill string, usually the BHA, causing the hole to pack off and the pipe to become stuck. The problem is exacerbated in overgauge sections where the annular velocities are reduced. Cuttings will build up and eventually slump into the hole.

High angle wells are more difficult to clean than vertical ones, because of the tendency of the drilled solids to fall to the low side of the hole. In a vertical well, provided the circulation rate is higher than the slip velocity of the cuttings, then the hole will be cleaned. In highly deviated wells, the cuttings have only a short vertical distance to fall, before they will lie on the low side of the hole. Beds of cuttings will be formed which are not easily removed. Problems can be caused when tripping out of the hole, as the BHA will be pulled into the cutting beds. The cuttings will be dragged up in front of the top collar or stabilizer, until the hole packs off or the pipe is pulled tightly into a plug of cuttings.

b) *Formation Instability*



Some formations can plastically extrude into the hole and close around the pipe, while others can slough and cause a hole to pack off. For example, coal is prone to sloughing, salt will extrude and shales can do either. Uncemented sands and gravels can slough into the hole, giving large overgauge sections and possible hole cleaning problems. Heavily fractured limestones can result in a succession of boulders falling into the well, jamming around the BHA and causing the pipe to stick.

Shales

The stability of shales is governed by several factors, including the weight of overburden, in-situ stresses, angle of bedding planes, moisture content and their chemical composition. Shales can be split into two categories:-

a) Brittle Or Sloughing Shales

These shales fail by breaking into pieces and sloughing into the hole. Sloughing can be recognized by large amounts of shale on the shakers at "bottoms up", drag on trips and high levels of fill.

b) Swelling Shales

Some shales swell as the result of a chemical reaction with water known as hydration. The clay platelets, which make up shales, are pushed apart by the water and the formation expands. The amount of swelling varies from the highly reactive "gumbos" to shales which hydrate very slowly. However, any swelling shale is a potential cause of stuck pipe.

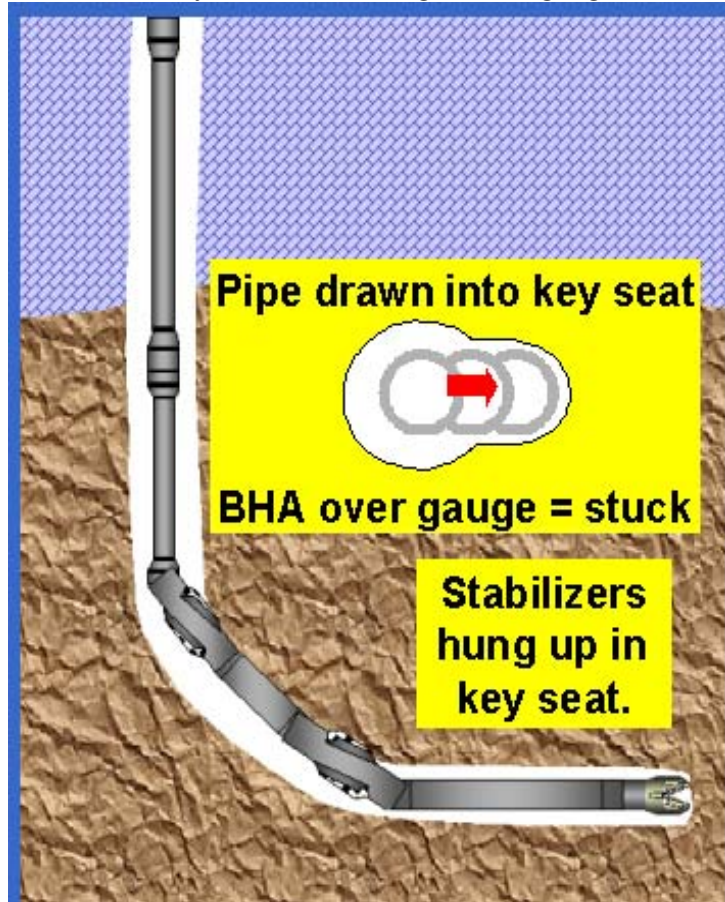
Gumbos will swell very rapidly and very dramatically. Given sufficient free water the clay platelets will separate completely, expanding to several times their original volume. The hole can be cleaned at controlled rates of drilling but it may need to be redressed after each joint, as the clays continue to swell.

**** Hole Orientation**

Shales are weaker along the formation bedding planes than across them. Because of this, holes drilled at different inclinations and directions through the same formation may vary greatly in stability. Increasing the mud weight will help to stabilize a formation, while frequent short trips and careful drilling practices can help to minimise stuck pipe risks.

d) **Key Seating** A key seat is caused by the drill string rubbing against the formation. The body and tool joints of drillpipe wear a groove in the rock about the same diameter as the tool joints. The wear is confined to a narrow groove, because the high tension in the drill string prevents sideways

movement. During a trip out of the hole, the BHA may be pulled into one of these grooves, which may be too small for it to pass through. See Figure 3. Key seats are often associated with doglegs, as the drill string will be forced into contact with the formation. The more severe the dogleg, the greater the side load will be and so the faster a key seat will develop. Other than doglegs, ledges are features which provide points of continuous contact. Further variations include key seats at casing shoes, where the groove is made in metal instead of rock. Development of key seats is dependant upon the number of rotating hours.



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d) Undergauge Hole And Assembly Changes

Abrasive hole sections will tend to not only dull bits, but also to reduce their gauge and that of the stabilizers. Attempting to maximise the length of a bit run in an abrasive formation may prove to be a false economy, as undergauge hole will inevitable lead to reaming operations. Reaming a long section will usually wear out a bit very quickly. A driller, tripping in at high speed, can jam a full gauge assembly into an undergauge hole and become stuck. Greater care is all that is needed to prevent this.

A flexible assembly can "snake" around doglegs that present an obstruction to a stiff assembly. Formation drilled with a limber BHA may appear to be clean when pulling out, but when running a stiffer BHA, the newly drilled hole will act as if it were undergauge. Again there will be a risk of sticking the pipe.

e) Drilling Plastic Salts

The plastic nature of salt formations may result in stuck pipe. When drilling into salt, stresses will be relieved and the formation will extrude into the borehole. The encroachment can often be measured in fractions of an inch, but this may be sufficient to cause a bit or stabilizer to become stuck.

The magnitude of the stresses and hence the rate of movement, will vary from region to region but is generally for formations below 2000 meters (6500 feet). Abnormal pressures and flowing salts may be experienced anywhere with unequal relieved stresses, but most commonly at the top of a formation or on the flanks of salt domes.

18. Fishing

A “fish” is a piece of equipment, a tool, a part or all of the drill string that is lost or stuck in the hole. Small pieces, such as a bit cone, or any other relatively small nondrillable items, are called junk or “fish” in the hole. These must be removed or fished out so that drilling operations can continue.

A number of ingenious tools and techniques have been developed to retrieve a fish. Fishing tools are divided into two groups:-

- 1) Tools used to fish junk .
- 2) Tools used to fish pipe.

1- Fishing for junk:

When a relatively small piece of equipment (junk) is lost in the hole, it may be retrieved using one of the following tools "Junk" or "boot" sub. This is run immediately above the bit to catch small junk thrown up by turbulence. It is normally run before running a diamond bit so that no fragments can damage the bit.

"Finger-type" or "poorboy" junk basket:

This cuts a small core, after which weight is applied to the tool and bends the bevelled fingers inward to trap the junk inside. This can be made "on the spot" from casing.

Core-type junk basket:

This is essentially a finger-type junk basket but has a mill shoe. Instead of applying weight to contain the core, this tool has "catchers" which grip the core and junk on the trip out.

Fishing Magnet:

This is used for picking up steel fragments.

Jet bottomhole cutter:

This is used when junk is so large or oddly shaped that it cannot be readily retrieved with regular junk baskets. It breaks up the junk into small pieces by use of a shaped explosive charge. The junk may then be retrieved using one of the above tools.

Grapple or rope spear

This is used to retrieve wireline in the hole.

2- Fishing for pipe:

When the drillstring has actually parted or is stuck in the hole, the operation for correcting the situation is called "fishing." (If the fish cannot be recovered, it must be cemented off and the hole is side-tracked). Some of the tools used for fishing are described below.

Mill

Milling is sometimes necessary in order to dress the top of a fish so that the selected fishing tool is able to make a firm positive catch.

Overshot

This is probably the first tool to be used when it is established that the top of the fish is fairly smooth. It can be a rotary taper tap or die or a more modern type which works like a set of "slips" in a core barrel to engage the top of the fish.

Wall-hook guide

This is used if the top of the fish is in a washed-out section of hole, and it takes the place of the regular guide on the bottom of an overshot. It engages the fish and guides it into the overshot.

Jar

This is used when a drillstring is stuck or when a "fish," caught in an overshot, cannot be pulled from the hole. In a normal drillstring a jar may be included in the middle of the collars, whereas in a fishing string it is placed immediately above the fishing tool. Jarring provides a method for giving an upward jerk to free the pipe. It works similar to a trip-hammer.

Free-point indicator and string shot

When fishing has not been successful, this is used to determine at what point in the hole the fish is stuck. It is an electronic instrument that can sense torque or movement; it is lowered by wireline as far as possible into the hole and raised slowly while the string is stressed. Below where the pipe is stuck no torque will be sensed, but the instrument gives a positive indication as soon as the free point is reached.

The free point indicator is raised until the string shot is positioned opposite a tool joint, one or two joints above the stuck point. Left-hand torque is applied to the drillpipe, and the primacord string shot is exploded. Loss of torque in the drillpipe is a definite indication that the tool joint has been loosened. The "back-off" is completed by further left hand rotation and by picking the pipe up a few feet.

Washover

This is a large-diameter pipe with a rotary cutting shoe on the bottom. It is run over stuck pipe in order to free it before fishing.

Spotting

This is used when jarring alone will not free the fish. Oil or special chemicals are spotted around the fish in an attempt to penetrate the wall cake, causing it to deteriorate and make the pipe slick. Spotting with water when differentially stuck,

and acid spotting when stuck in limestone, are often used in an attempt to free the pipe.

If spotting and jarring do not free the fish, the "free point" is located and the portion of the drillpipe above is "backed off." washover operations can then be carried out to retrieve the stuck portion of fish.

Safety joint

This is a coarse-threaded joint which may be easily released and run above a fishing tool in case it should happen that the fish cannot be freed and the fishing tool cannot be released.

19. Wireline logging (electric) logging

A valuable technique for evaluating a borehole is the wireline well logging.

An electric logging company is called to the well while the crew trips out all the drill string. Using a laboratory, truck-mounted for land rigs and permanently mounted on offshore rigs the loggers lower devices called logging tools (or sonde's) into the well on wireline. The tools are lowered all the way to bottom and then reeled slowly back upwards. As the tools are coming up the hole they are able to measure the properties of the formations they pass.

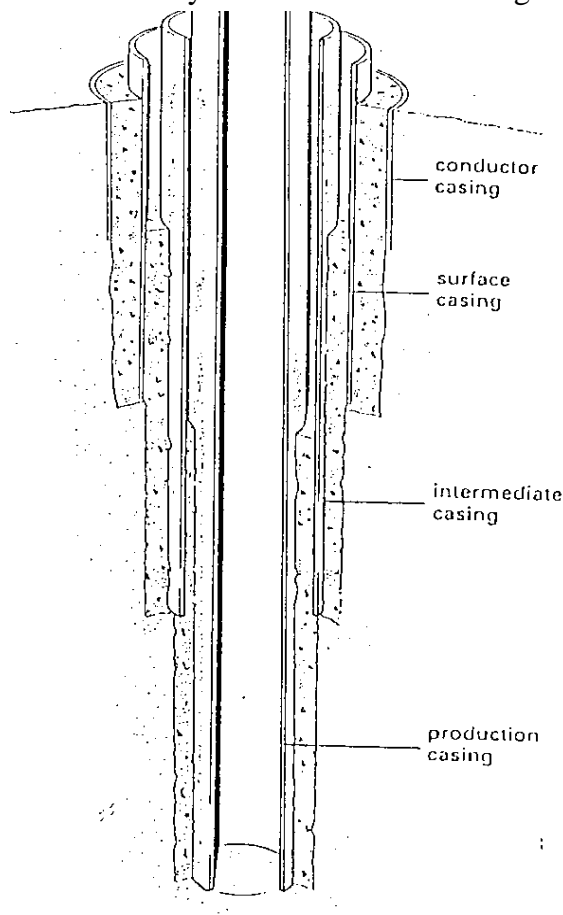
Some logs measure and record natural and induced electricity in formations. Other loggings formations with sound and measure as well as record sound reactions. Radioactivity logs measure and record the effects of natural and induced radiation in the formations. These are only a few of many types of E-logs available.

Since all the logging tools make a record, which resembles a graph or an electrocardiogram (EKG). The records, or logs can be studied and interpreted by an experienced geologist to indicate the existence of oil or gas and how much may exist. Computers have made the interpretation of logs much easier.

20. Casing

Casing is steel pipe placed in an oil or gas well at the end of every drilled phase, and then cemented in place prior to striating drilling the lower smaller hole section. See figure 28

(Figure 38) Cross Section shows Casing Profile



FUNCTIONS OF CASING:

1. Prevents the hole from caving or collapsing.
2. Prevents loss of drilling fluids into weak formations.
3. Isolate troublesome formations.
4. Prevents communication between formations.
5. Provides means of extracting hydrocarbons if the well is productive.
6. To effect a method of control and safety as depth increases.
7. Provides a means of support for the well head equipment.

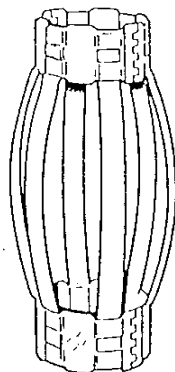
Once the drill pipe is out, the casing crew moves in to do their work., the first string of casing they run is called surface casing. Other strings of casing include intermediate (or protective) and production casing. A short string of casing called a "liner" may be hung-off from another string instead of extending up to the surface. Running casing into the hole is very similar to running drill pipe, except that the casing diameter is much larger and thus requires special elevators, tongs and slips to fit it.

Casing Accessories

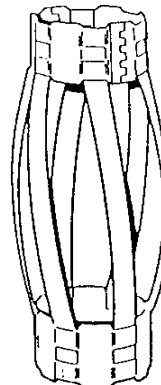
To lower an open ended pipe in an open hole for great depths could be a difficult process, the pipe would tend to dig into the formation as it is lowered. Also casing may tend to lie to one side of the hole,...etc. In order to overcome such difficulties and to assist in the placement of the cement a number of items or equipment are used; these are called "Accessories".

A number of centralizers and scratchers are often installed on the outside of the casing before it is lowered into the hole.

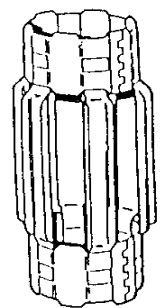
The centralise are attached to the casing and since they have a bowed spring arrangement keep the casing centred in the hole after it is lowered in. Centralised casing can make for a better cement job later.



a straight
centralizer

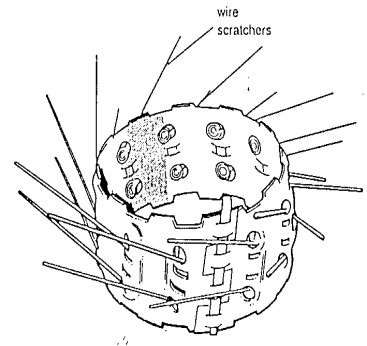


a spiral
centralizer



a positive
centralizer

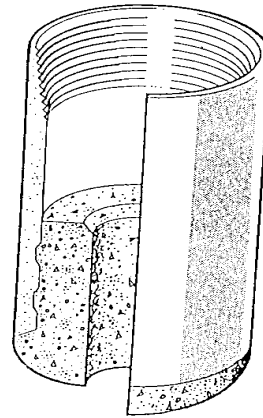
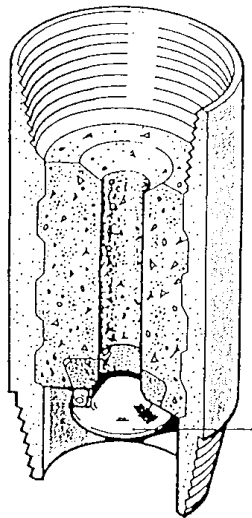
The scratchers also came into play when the casing is cemented. The idea is that if the casing is moved up and down, or rotated (depending on scratchier design) the scratchers will remove the wall cake formed by the drilling mud and the cement will thus be able to bond better to the hole.



Other casing accessories include:

A float collar; a device with a valve, installed in the casing string two or three joints from bottom. A float collar is designed to serve as a receptacle for cement plugs and to keep drilling mud in the hole from entering the casing. Just as ship floats in water, casing floats in a hole full of mud (if mud is kept out of the casing). This buoyant effect helps relieve some of the weight carries on the mast or derrick as the long string of heaving casing hangs suspended in the hole. Alternatively the casing may be allowed to fill up to avoid the

possibility of collapsing the casing at greater depths. This is affected by a surface or automatic filling via differential fill - up float shoe.



A guide shoe; a heavy steel - concrete piece attached to the bottoms joint of casing that helps guide the casing past small ledges or debris in the hole .

21. Cement

After the casing string is run, the next task is cementing the case in the place. An oil well cementing service company is usually called-in for this job, although, as when casing is run, the rig crew is available to lend assistance.

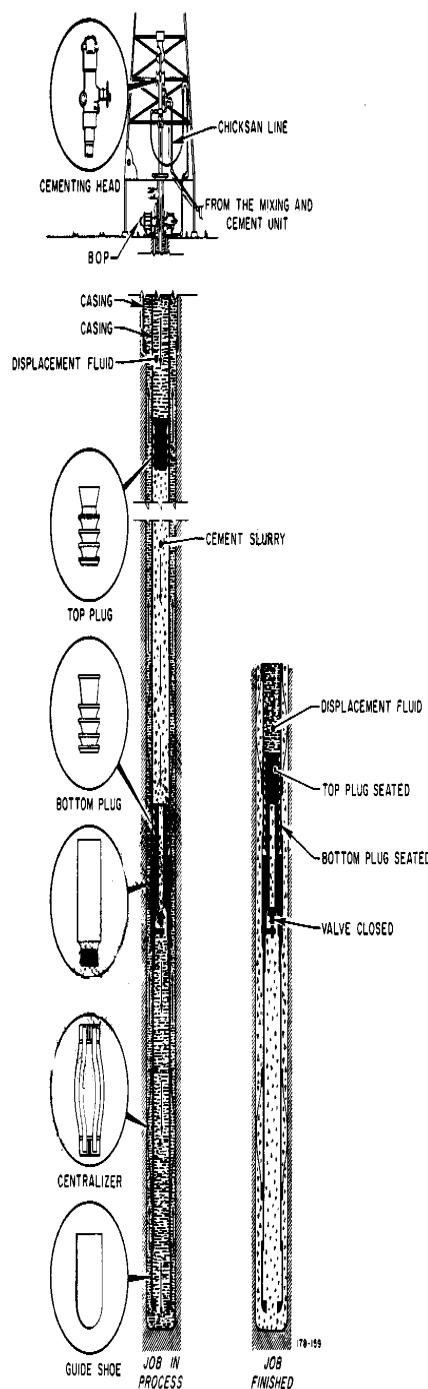
Cementing service companies stock various types of cement and have special transport equipment to handle this material in bulk.

Bulk cement storage and handling equipment is moved out to the rig, making it possible to mix large quantities of cement on site. The cementing crew mixes the dry cement with water, using a device called a job mixing *Hopper*. The dry cement is gradually added to the hopper and a jet of water thoroughly mixes with the cement to make a slurry (very thin, watery cement). Weighted slurries are often used to insure a control of the formation pressure.

Special (cement) pumps pick up the cement slurry and send it up to a valve called a cementing head (also called a plug container) mounted on the topmost joint of casing that is hanging in the mast or derrick a little above the rig floor.

Just before the cement slurry arrives a rubber plug (called the bottom plug) (Figure 31) is released from the cementing head and precedes the slurry down the inside of the casing. A pre-calculated volume of cement that is equal to the annular volume between casing pipe and hole is then pumped-in, then a top plug (Figure 31) is released from the circulation head and soon mud is pumped behind the top plug -usually with the rig pump to drive the cement to the annulus; This process is called "Cement Displacement".

The bottom plug stops or "seats" in the float collar, but continued pressure of pumps ruptures a passageway through the bottom plug, thus the cement slurry passes through it and continues on down the casing. The slurry then flows out through the opening in the guide shoe and starts up the annular space between the outside of the casing and



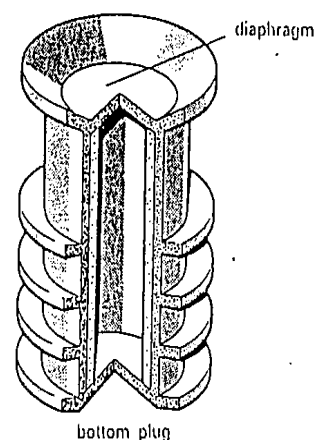
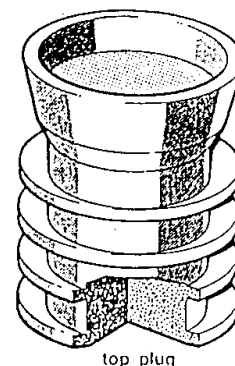
walls of the hole. By the time the top plug seals on or “bumps” the bottom plug in the float collar; pump pressure increased sharply which signals the pump operator to shut-off the pumps, the cement is only in the casing below the float collar and in the annular space and the rest of the casing is full of displacing mud.

After the cement is run, a waiting time is allowed to allow the slurry to harden. This period of time is referred to as **Waiting On Cement** or simply “**WOC**”.

After the cement hardens, tests may be run to ensure a good cement job, for cement is very important. Cement supports the casing so the cement should completely surround the casing; this is where centralizers on the casing help. If the casing is centred in the hole, a cement sheath should completely envelop the casing. Also cement seals-off formations to prevent fluids from one formation migrating up or down the hole and polluting the fluids in another formation. For example, cement can protect a freshwater formation (that perhaps a nearby town is using as a drinking water supply) from saltwater contamination. Further, cement protects the casing from the corrosive effects that formation fluids (as salt water) may have on it.

After the cement hardens and tests indicate that the job is good, the rig crew attaches or nipples up the blow-out preventer stack on the top of the casing. The BOP slack is then pressure tested and drilling is resumed.

After nipping up the BOP stack a smaller bit on a slick bottom hole assembly is run in hole to drill out cement. The slick assembly is an assembly without stabilizers to avoid hitting the casing inside. This bit drills out the float collars and the drillable casing shoe along with the cement in between.



(Figure 31)

22. Completing the well & Setting Production Casing

After the operating company carefully considers all the data obtained from the various tests it has ordered to be run on the formation or formations of interest, a decision is made on whether to set production casing and complete the well - or to plug and abandon it. If the decision is to abandon it, the hole is considered to be dry, that is, not capable of producing oil or gas in commercial quantities. Some oil or gas may be present but not sufficient to justify the expense of completing the well. Several cement plugs are set in the well to seal it off more or less permanently. Sometimes wells that were plugged and abandoned as dry at one time in the past may, however, be reopened and produced if the price of oil or gas has become more favourable. The cost of plugging and abandoning a well may only be a few thousand dollars. Contrast that cost with the price of setting a production string of casing. The operator's decision, therefore, is not always easy.

If the operating company decides to set casing, this will be brought to the well and for one final time the casing and crew run and cement a string of casing. Usually, the production casing is set and cemented through the pay zone, that is, the hole is drilled to a depth beyond the producing formation, and the casing is set at a point near the bottom of the hole. As a result, the casing and cement actually seal off the producing zone - but only temporarily. After the production string is cemented, the drilling contractor has almost finished his job except for a few final touches.

23. Perforating production casing

Since The pay zone is sealed-off by the production string and cement, perforation must be made in order for the oil or gas to flow into the wellbore.

Perforations are simply holes that are made through the casing and cement and extend some distance into the formation. The best common method of perforation, incorporates shaped-charge explosives (similar to those used in armour-piercing shells).

Shaped charges accomplish penetration by creating a jet of high pressure, high-velocity gas. The charges are arranged in a tool called a gun that is lowered into the well opposite the producing zone. Usually the gun is lowered in on wireline. When the gun is in position, the charges are fired by electronic means from the surface. After the perforations are made, the tool is retrieved. Perforating is usually performed by a service company that specialises in this technique.

24. Drill Stem Test (DST)

Another helpful technique is the drill stem test (DST) tool, which is made up on the drill string (the drill stem) and set at the depth required. A packer, which is an expandable hard-rubber sealing element, seals-off the hole above it by expanding when weight is set down on it. A valve is opened to allow any formation pressure and fluids present to enter the tool. A recorder in the tool makes a graph of the formation pressures. Then the packer is released and the tool retrieved back to the surface. By looking at a record of the downhole pressures and surface flows a good measure of the characteristics and contents of the reservoir can be obtained. Other valves or points are opened to expose the formation to atmospheric pressure, allowing the well to flow.

25. Acidizing

Sometimes, petroleum exists in a formation but is unable to flow readily into the well because the formation has very low permeability. If the formation is composed of rocks that dissolve upon being contacted by acid, such as lime stone or dolomite, then a technique known as acidizing may be required.

Acidizing is usually performed by an acidizing service company and may be done before the rig is moved off the well or after the rig is moved away. In any case, the acidizing operation basically consists of pumping anywhere a quantity of acid down the well. The acid travels down the tubing, enters the perforations and contacts the formation. Continued pumping forces the acid into the formation where it etches channels; these provide a way for the formation's oil or gas to enter the well through the perforations.

26. Fracturing

When sandstone rocks contain oil or gas in commercial quantities but the permeability is too low to permit good recovery, a process called fracturing may be used to increase permeability to a practical level.

To fracture a formation, a company providing this service pumps a specially blended fluid down the well and into the formation under great pressure. Pumping continues until the formation literally cracks open.

Sand, walnut hulls or aluminium pellets are mixed into the fracturing fluid. These materials are called proppants. The proppant enter the fractures in the formation. When pumping is stopped and the pressure is allowed to dissipate, the proppant remains in the fractures. Since the fractures try to close back together after the pressure on the well is released, the proppant is needed to hold or prop the fractures open. These propped-open fractures provide passages for oil or gas to flow into the well.

27. Installing the Christmas Tree

Even though the oil or gas can flow into the casing after it is perforated, the well is not usually produced through the casing. Instead, a small diameter pipe called “**tubing**” is placed in the well to serve as a way for the oil or gas to flow to the surface. The tubing is run into the well with a packer. The packer goes on the outside of the tubing and is placed at a depth just above the producing zone. Then the packer is expanded, it grips the walls of the production casing and forms a seal in the annular space between the outside of the tubing and the inside of the casing. As the produced fluids flow out of the formation through the perforations, they are forced to enter the tubing to get to the surface.

When casing is set, cemented and perforated, and when the tubing string is run, then a collection of valves called a “**Christmas Tree**” is installed on the surface at the top of the casing. Like so many terms in the oil industry, no one knows why this device on top of the well is called a Christmas tree. Perhaps all the valves and piping reminded someone of the traditional Christmas tree. The tubing in the well is connected to the Christmas tree, so as the well's production flows up the tubing, it enters the Christmas tree. As a result, the production from the well can be controlled by operating or closing valves on the Christmas tree.

Usually, once the Christmas tree is installed the well is complete. The drilling contractor has done his job according to the drilling contract and he can move the rig to another location to start another well drilling process all over again.

5. Mud Logging Definition

- Mud logging is a service that qualitatively and quantitatively obtains data from, and makes observations of, drilled rocks, drilling fluids and drilling parameters in order to formulate and display concepts of the optional, in situ characteristics of formations rocks with the primary goal of delineating hydrocarbon “shows” worthy of testing.
- The mud logging unit is the information center on the rig site to serve both exploration and drilling.

General Purposes:

- Optimized drilling efficiency.
- Comprehensive formation evaluation.
- Improved well site safety.

Role played by Mud Logging Unit

The mud unit is located very close to the rig floor. A number of cables extends from the unit to a number of sensors installed at different locations on the drilling rig. These sensors are used to measure many important variables or parameters of the rig operations.

A- The essential role that the unit plays on board, is the collection of the rock cuttings which is geologically described, examined for any oil shows and then packed according to the exploration company requirements.

B- The mud logging unit is responsible for the hydrocarbon gas monitoring while drilling. These gases are detected as a total value then are analyzed to their components.

C- The mud logging unit is responsible for the detection of the Hydrogen sulfide (H₂S) gas while drilling which is very dangerous if it is not detected in the very early stage.

D- The mud logging unit is responsible for the monitoring of the drill fluid volume second by second and to immediately inform the personnel in charge about any change in that volume (Loss/Gain).

E- The mud logging unit is responsible for the generation of mud logs and graphs during the drilling of the well, acquisition of the data and producing a final well report.

F- The mud logging unit is responsible for the monitoring of the drilling parameters such as : WOB, RPM, TRQ. ...etc.,. And to inform the personnel in charge about any anomalies or figures that could be out of the set ranges.

G- The mud logging unit is responsible for confirming with the driller about any drilling breaks.

H- The mud logging unit is responsible for monitoring the trips and updating a trip sheet at a five-stand basis. This trip monitoring sheet includes the calculated/observed

hole fill-up or string displacement along with remarks on string overpull, tight spots and running speed.

I- The mud logging unit extends its service to the detection and evaluation of the formation pressure, the hydraulics optimization and the well control.

The mud logging unit is considered the information center of the rig site as the unit participates in the monitoring of each and every rig operation.

28. TYPES OF MUD LOGGING UNITS

Mud logging units can be classified into two main categories depending on the method of data acquisition and processing:-

Off-line mud logging units.

On-line mud logging units.

A- Mud Logging Off-line service features

The off line mudlogging unit includes a number of separate panels. Each panel works independently and is responsible for measuring a definite parameter. There is no communication between these panels. No automatic calculations can be done and no data storage. All panel calibrations are done manually.

B- Mud Logging On-line service features

1-Minimum human interference:

Operation, calibration and data processing starts at the sensing point and goes all the way until the final output is produced. The result is:

- Random errors minimized, i.e best accuracy.
- More time for interpretation.
- More time for monitoring.

2- Fully computerized service with powerful software:

- High speed data processing (possible data transmission)
- Better presentation of data.
- On time decision making.

3- Best possible equipment design in the industry:

- Maximum possible accuracy.
- Minimum systematic errors.
- Minimum down time.

4- Intrinsic safety:

- Safety environment
- Safety equipment
- Efficient warning system

MUD LOGGING ON-LINE UNIT EQUIPMENT

- 1- Geological equipment -Microscope - Fluoroscope - Auto Calcimetry Kit
 - shale Density kit
- 2- Remote pump stroke counters
- 3- Multi-channel, high resolution chart recorders
- 4- Flame ionization hydrocarbon gas detector (FID)
- 5- Flame ionization gas chromatograph (C1 - C5)
- 6- Drill monitor panel
- 7- Depth - WOB - RPM - Torque
- 8- Pressure detection system standpipe pressure (SPP), Casing pressure
- 9- Pit volume totalizer
- 10- Mud weight (in and out)
- 11- CRT information system
- 12- Mud temperature (in and out)
- 13- Mud resistivity (in and out)
- 14- Mud conductivity (in and out)
- 15- H₂S gas detector
- 16- CO₂ gas detector
- 17- PC computers (on-line & off-line)
- 18- Mud flow sensors (in and out)
- 19- Central air-conditioning units
- 20- Unit voltage regulator
- 21- Uninterruptable power supply (UPS)

General features of Sperry- Sun On-line Mud Logging unit LS-2000:

- Continuous real-time monitoring.
- All equipment measured data is fed directly to the computer.
- LS 2000 is multi-tasking real-time data acquisition and monitoring system.
- Automatic determination of the operation status.
- The unit is constructed to US Coast Guard safety regulations .
- Skid mounted
- Pressurized insulated shell.
- Exploration proof junction boxes.

- Intrinsic safety through the use of safety barriers.
- Non volatile data memory buffer which enable to retain all the data the event of power failure or gas hazard shut down.
- Open system structure, this gives the system flexibility to upgrade when new multibus compatible boards become available.
- On-line calculation of appropriate values, LS 2000 system automatically perform a variety of calculations on the parameters monitored created records for data storage and produces reports displaying the information.
- LS 2000 software can construct a very strong and logic alarm net to cover up to 30 parameters, which is very important for rig safety and lead to minimizing the down time.
- Ls 2000 sensors are designed to provide high accuracy and to minimize the down time. All the sensors are calibrated and controlled by the computer.

29. DUTIES & RESPONSIBILITIES

i) MUD LOGGING UNIT CAPTAIN

Basic Function:

The Unit captain is the senior mud logging engineer on the location. He has primary responsibility for the maintenance, management and provision of service by the logging unit, its equipment and personnel to the client.

The unit captain is the representative of Sperry- Sun logging systems at the well site. He is responsible for the maintenance and correct operation of the equipment supplied to provide the service. He is responsible for the collation and presentation of the information monitored in accordance with company standard procedures and customer requirements to ensure a high quality of service.

Position Responsibilities and Duties:

The following responsibilities include, but are not restricted to:-

1. The logging unit is kept clean, neat and tidy at all times.
2. The unit captain is responsible for, and ensure that : all equipment and sensors are maintained, serviced and calibrated according to standard company operating procedures.
3. The unit captain is responsible for, and will ensure that: The unit diary, spare parts inventory, equipment status reports, calibration reports and other specified equipment monitoring reports are kept up to date.
4. The unit captain is familiar with the function, operation and routine maintenance of all logging system equipment at the location. He will implement any rig-up, rig - down and routine maintenance and calibration programmes as instructed by the operations or unit supervisor.

5. The unit captain is familiar with the hardware configuration of the computer system and is capable of operating the software.

Well Monitoring:

- 1- The unit captain will ensure that the unit is manned at all times and the well is constantly monitored.
- 2- All pertinent data is recorded on BLS data sheets accurately, legibly and completely.
- 3- All sensors are monitored for variations from expected readings. Customer and Rig contractor personnel are informed as per prescribed job procedures quickly, efficiently and effectively.
- 4- All hole and pipe displacements are accurately monitored on all trips in and out of the hole. Discrepancies are to be noted and the relevant people informed.

Data Collection and Presentation:

- 1- Depth, drilling data and log data must be recorded accurately and checked against rig recorded data.
- 2- Gas and mud samples for gas analysis should be collected in the correct manner and run through the THA , Gas chromatography and steam still in accordance with standard operating procedures.
- 3- All chart records should be labelled and annotated in accordance with standard operating procedures.
- 4- All data sheet should be kept current.
- 5- All cuttings samples must be caught at the correct time to give a true representation of the interval. All samples will be described as per standard operating procedures.
- 6- All samples will be marked and labelled as instructed by the unit supervisor and as per customer requirements. Storage and transportation will be as directed by the unit supervisor.
- 7- The unit captain will supervise and be responsible for the quality of the production of the Mud log.

Customer Relations:

- 1- The unit captain will, at all times , maintain a professional and responsible attitude and appearance in relations with the customer and rig personnel.
- 2- All customer logs and reports are drawn and written in a neat, concise and uniform manner to sperry-sun Logging systems and customer requirements and are delivered to the schedule and locations required by the customer.
- 3- All relevant personnel are informed of all pit gains and losses, gas /oil shows, drill breaks, washouts and other drilling and geological changes as specified by logging systems or the customer.
- 4- Customer requirements will be actively determined, customer satisfaction will be monitored. Information on the full range of products and services will be provided.

Pre-job meetings, job follow up and office calls on the customer will be performed as necessary and as required.

- 5- All requests by the customer Representative will be carried out wherein they concern the above duties.

Safety

1. Safety is the responsibility of every employee. The safety rules and guidelines issued by the company and by the customer must be fully understood and followed.
2. The unit captain will ensure that all safety equipment in the mud logging unit is kept in good condition.

Training

1. The unit captain will attend training courses as directed, and will train for promotion to higher grades within the company.
2. Assist in the training of the new employees in the fundamentals of logging techniques and job requirements.
3. Train new personnel in the use and maintenance of the equipment and ensure that they become competent with logging techniques. Co-ordinate with the Q.C (Quality Control) training department for materials and procedures to facilitate rigsite training.
4. Submit to the relevant supervisor, written appraisal reports on trainees for each training period.
5. Will learn, understand and apply new products, services, software and hardware as introduced or revised by the company.

Company

- 1- The unit captain will be neat, professional, mature and responsible in attitude and appearance.
- 2- Perform duties and responsibilities in a correct efficient and mature manner in CO-operation with other assigned logging engineers and as directed by the unit supervisor.
- 3- Furnish all reports, forms, CV's as and when required. Reply to directives and memos within specified deadlines or in a timely manner.
- 4- Check in to local operations base and/or slough office prior to travelling after returning from the field.
- 5- Observe company rules regarding company vehicles or when travelling on company business.
- 6- Obey all local laws and act as befits employee of the company.

MUD LOGGER**Job Descriptions**

The job title and job description are not necessarily descriptive of all duties, and do not restrict flexibility as directed by management.

Basic function

The Mud logging Engineer is the representative of sperry-sun logging systems at the well site. He is responsible for the maintenance and correct operation of the equipment supplied to provide the service. He is responsible for the collation and presentation of the information monitored in accordance with company standard procedures and customer requirements to ensure a high quality service.

Position Responsibilities and Duties

The following responsibilities include, but are not restricted to:

1. The logging unit is kept clean, neat and tidy at all times.
2. All equipment and sensors are maintained, serviced and calibrated according to the standard company operating procedures.
3. The unit diary, spare parts inventory, equipment status reports, calibration reports and any other specified equipment monitoring reports are kept up to date.
4. The Mud logger is familiar with the function, operation and routine maintenance of all logging systems equipment at the location. He will implement any rig-up, rig-down and routine maintenance and calibration programmes as instructed by the operations or unit supervisor.
5. The Mud logger is familiar with the hardware configuration of the computer system and is capable of operating the software.

Well Monitoring

1- The mud logger will ensure the unit is manned at all times and the well is constantly monitored.

2- All pertinent data is recorded on the data sheets accurately, legibly and completely.

All sensors are monitored for variations from expected readings. Customer and rig contractor personnel are informed -as per the described job procedures- quickly, efficiently and effectively.

3- All hole and pipe displacements are accurately monitored on all trips- in and out-of the hole. Discrepancies are to be noted and the relevant people to be informed.

Data Collection and Presentation

1- Depth, drilling data and lag data must be recorded accurately and checked against rig recorded data.

2- Gas and mud samples for gas analysis should be collected in the correct manner and run through the THA, Gas chromatography and steam still in accordance with standard operating procedures.

3- All chart recorders should be Labelled and annotated in accordance with standard operating procedures.

- 4-** All data sheets should be kept current.
- 5-** All cuttings samples must be caught at the correct time to give a true representation of the interval. All samples will be described as per the standard operating procedures.
- 6-** All samples will be marked and labelled as instructed by the unit supervisor and as per the customer requirements. Storage and transportation will be as directed by the unit supervisor.

Customer Relations

- 1-** The mud logging will at all times maintain a professional and responsible attitude and appearance in relations with the customer and rig personnel.
- 2-** All customer logs and reports are drawn and written in a neat, concise and uniform manner to logging systems and customer requirements and are delivered to the schedule and locations required by the customer.
- 3-** All relevant personnel are informed of all pit gains and losses, gas/oil shows, drill breaks, washouts and other drilling and geological changes as specified by logging systems or the customer.
- 4-** Customer requirements will be actively determined, customer satisfaction will be monitored. Information on the full range of products and services available will be provided.
- 5-** Pre-job meetings, job follow up and office calls on the customer will be performed as necessary and as required.
- 6-** All requests by the customer representative will be carried out wherein they concern the above duties.

Safety

- 1-** Safety is the responsibility of every employee. The safety rules and guidelines issued by the company and by the customer must be fully understood and followed.
- 2-** The mud logger will ensure that all safety equipment in the mud logging unit are kept in good condition.

Training

- 1-** The mud logger will attain training courses as directed, and will have training for the promotion to higher grades within the company.
- 2-** Assist in the training of the new employees in the fundamentals of logging techniques and job requirements.
- 3-** Will learn, understand and apply new products, services, software and hardware as introduced or revised by the company.

Company

- 1-** The mud logger will be neat, professional, mature and responsible in attitude and appearance.
- 2-** Perform duties and responsibilities in a correct, efficient and mature manner in CO-operation with other assigned logging engineers and as directed by the unit supervisor.
- 3-** Furnish all reports, forms, CV's as and when required. Reply to directives and memos within specified deadlines or in a timely manner.
- 4-** Check in to local operations base and/or slough office prior to travelling and after returning from the field.
- 5-** Observe company rules regarding company vehicles or when travelling on company business.
- 6-** Obey all local laws and act as befits and employee of the company.

6. THE MUD LOGGING THEORY & LAG

Theory

The mud logging theory is based on the mud cycle principle. The mud is sucked from the pits (Active Pit) and pumped via the drilling string down to the hole bottom. The mud is then bumped against gravity through the annulus up to the shakers. The time necessary to get the drilled samples to the surface is exactly the time required to pump the mud volume through this passage. This is calculated and is known as Lag time or lag strokes

The calculation and practical application of the lag is of primary importance in mud logging and relates to the all data that the mud transmits to the surface.

The mud actually carries the information that we require from the bit depth to the surface and the time that the mud takes to get from the bit to surface is the basic calculation made. The factors that affect the time or lag of the mud are the flow rate of the mud, the configuration of the well; the sizes and depths of the different hole sections and the drill string sections' dimensions.

Lag definitions:

- Lag time is the time the mud takes to travel inside the hole between two specified depth points.
- The time taken between the surface to the bottom of the hole is called "lag down" or "Lag in".
- The time taken between the bottom of the hole to the surface is called "lag-up" or "bottoms' up".
- The surface to surface time is called "Complete cycle" or In/Out time.

It is more practical to calculate lag in terms of pump strokes as the flow rate is not necessarily constant.

To calculate the lag the hole dimensions must be known as well as the drill string dimension. Most holes have at least two section of different diameters and towards the end of the well may have more (riser, casing liner, and open hole). Added to this is the fact that the drill string will usually have sections of different diameters (drill pipe, heavyweight drill pipe and drill collars, etc).

Two techniques may be applied to calculating the annular volume, These are :-

In The first method, the lengths and the dimensions of each section of the annulus are determined, the volumes are calculated and totalized. Then The lag equations are applied to determine the equivalent times and strokes.

The second method involves calculating the volume of the hole and the volume of the drill string (metal and internal capacity) and then subtracting the values from each other to determine the lag time and strokes for the whole well. The first method is the one preferred because it informs the logger of the exact nature of the various annular

sections and their individual volumes. This also helps in the calculations of the annular pressure drops.

With the use of the off-line mudlogging units the increase with depth should be calculated for a given length of hole by calculating the annular volume of the hole (bit diameter) filled with drill pipe. This should be added to the total annular volume to update the lag calculation to the current depth. For the On-Line logging unit this is automatically calculated and added as the depth increases.

The lag, as already mentioned, is most accurately counted in pump strokes. The annulus volume divided by the pump output per stroke will give the number of strokes needed to displace the mud up the annulus.

It is possible to monitor the lag in time units although this practice is much less accurate and very prone to errors. The most common error is to fail to keep a record of the amount of time that the pumps are off due to connections etc. The lag will be delayed by this amount.

LAG EQUATIONS

A. Converting Barrels → Gallons:

$$\text{Gallons (gal)} = \text{Barrels} \hat{=} 42$$

B. Converting Gallons → Barrels:

$$\text{Barrels (bbl)} = \text{Gallons} \div 42$$

C. Calculating Pipe Volume:

$$\text{Pipe Volume (bbl)} = \frac{(\text{Pipe / Collar ID}^2) \times \text{Length(ft)}}{1029}$$

C. Calculating Annular Volume:

$$\text{Ann. Volume (bbl)} = \frac{(\text{Hole / Casing ID}^2 - \text{Pipe / Collar OD}^2) \times \text{Length(ft)}}{1029}$$

D. Calculating lag-in strokes:

$$\text{Lag - in strokes} = \frac{\text{Annular Volume (bbl)}}{\text{Pump Output (bbl / stk)}}$$

E. Calculating lag-in minutes:

$$\text{Lag - in minutes} = \frac{\text{Lag - in strokes}}{\text{Pump Rate (spm)}}$$

F. Converting Meter → Ft:

$$\text{Feet (Ft)} = \text{Meter} \hat{=} 3.281$$

G. Converting Cu. inch → bbl:

$$1 \text{ bbl} = 9702 \text{ cu. inch}$$

H. Converting gcc → ppg:

$$\text{ppg} = \text{gcc} \times 8.33$$

lag Correction

Using the correct lag is vital to the geologist so that samples and hydrocarbon shows are described at the correct depth from which they came.

If the open hole section is in gauge; then the actual lag will be the same as the calculated lag. This is rarely the case in practice as most of the salt sections and some shale sequences tend to become washed out. Therefore carbide lag checks should be run frequently to determine the actual lag.

The procedure for carbide lag is to wrap a quantity of fine carbide in paper towel and place it inside the pipe at a connection. The action of water on the carbide will release acetylene gas which on circulating out of the system will be detected by the gas detector. Since the gas has to travel down the pipe to the bit and then to the surface, it is necessary to calculate the following:

1. The number of strokes from the surface to the bit inside the pipe.
2. The total number of strokes from starting up the pump until the gas arrives at the surface.
3. Subtract 1 from 2

⇒ The resulting number of strokes is the actual lag time. From this it is possible to estimate the amount of washout in the hole.

Apart from making regular carbide lag checks, a check should be made if for any reason the lag becomes suspect; for example the cuttings do not correspond with the drill rates from which they are supposed to come, or connection gas does not appear at the correct time.

If for some reason, carbide is not available a perfectly good lag check can be obtained by using rice or lentil. The main disadvantage of this is that it is necessary to stay and watch the shakers when the rice is due appear, or it could well be missed.

Rates of travel up the annulus differ for gas and cuttings as the cuttings will tend to slip back due to slip velocity. Slip velocity depends

on the cuttings size density the mud properties flow rate and hole size.

Lag calculation example:**GIVEN:**Pump information

pump output = 0.123 bbls/stroke

pump rate = 75 spm

Drill string information

Drillpipe : 5" OD 4.276" ID length 8075'

Heavy-weight Drillpipe: 5" OD 3.000" ID Length 275'

Drill collars: 8" OD 2.813" ID Length 650

Hole information

Casing : 13 3/8" OD 12.415" ID Length 3500

Open hole : 12.25" OD

TD : 900'

CALCULATE:

- Calculate the volume of mud in the Drillpipe, Heavy-weight and collars.
- Calculate the annular volume for each annular section.
- Add the section annular volumes to give the total annular volume.
- Calculate the lag in minutes.

QUESTION

Why is using pump strokes a much more accurate method of lag determination than using time?

ANSWERS

A useful and clear way of working out the lag is to draw a diagram of the well showing the different hole sizes and drill string dimensions. On this diagram the length and the depth of each section are indicated.

i) Volume of mud in the string:

a) Drillpipe: $(4.276^2/1029) \times 8075 = 143.5$ bbls

b) Heavy-Weight: $(3^2/1029) \times 275 = 2.4$ bbls

c) Drill collars: $(2.813^2/1029) \times 650 = 5$

$$a+b+c = 150.9 \text{ bbls}$$

ii) Annular section volumes:

a) Casing – Drillpipe: $((12.145^2 - 5^2)/1029) \times 3500 = 439.2$ bbls

b) Open hole – Drillpipe: $((12.25^2 - 5^2)/1029) \times 4575 = 556.0$ bbls

c) Open hole - Heavy Weight: $((12.25^2 - 5^2)/1029) \times 275 = 33.4$ bbls

d) Open hole - Drill collars: $((12.25^2 - 8^2)/1029) \times 650 = 54.4$ bbls

$$a+b+c+d = 1083.0 \text{ bbls}$$

iii) Lag in strokes

$$1083.0/1.23 = 8805 \text{ strokes}$$

iv) Lag. in minutes

$$8805/75 = 117.4 \text{ min}$$

Trip Monitoring

Trip monitoring is considered one of the most important of the duties and responsibilities of the mud logger. The mud logger should not feel relaxed during trip times as statistics indicate that the most of the serious well problems and disasters have happened while tripping.

A. TRIP-IN MONITORING PROCEDURES

1. Calculate metal displacement for each string section.
2. Check which tank should receive the displaced mud.
3. If displaced mud will return to active pit, check if the surface tanks (sand trap) are filled:-

3.a. If they are filled:

Mud should return to active pit once tripping-in starts.

3.b. If they are not filled:

Mud can not be monitored in the active pit until surface tanks get filled. Therefore you must either:-

- Inform driller and Co. Man that they should fill the surface pits prior to tripping-in; .
- . .OR Start the monitoring once the surface tanks gets filled and the displaced mud starts returning to active pit. In this case, estimate how many bbls would be required to fill surface tanks and how many stands should run-in to displace this required volume.

Note that surface tanks are monitored manually.

4. When displaced mud returns directly to the active system, one of the following PVT monitoring trends would be expected:

P V T		TREND	INTERPRETATION	ACTION
Steady			Mud losses due to surge action	Inform driller and Co. Man.
Showing increase		Increase is equal to the metal displacement	Everything is OK	No action.
		Increase is less than the metal displacement	Partial mud loss	Inform driller and Co. Man.
		Increase is more than	1. Well flowing	Inform driller and Co. Man.
		the metal displacement	. Jet plugging (pipe is not filled completely)	Ask driller to fill the pipe.

What would a trip schedule tell you when running pipe in the hole:

By monitoring the trip schedule while RIH, the mud displacement will schedule will dictate if hole is standing up with the added pressure (surge caused by lowering pipe)

Stands (94 ft.)	Displacement (BBL)		Time	Measured Trend Differences (BBL)		
	Calculate d (Cum.)	Actual (Cum.)		Calcu- lated	Actual	Trend Change
1 - 4 DC	13.2	13.0	0620	13.2	13	-0.2
5 - 8	26.4	26.0	0640	13.2	13	-0.2
9 - 11	36.3	35.5	0700	9.9	9.5	-0.4
11 - 20	43.0	41.8	0720	6.7	6.3	-0.4
21 - 30	49.7	47.8	0740	6.7	6.0	-0.7
31 - 40	56.4	52.8	0700	6.7	5.0	- 1.7
41 - 50	63.1	52.8	0720	6.7	4.0	- 2.7

If a logger looks at only volume (actual vs. calculated), everything might look good after POH with 90 stands. However, the trends tell a completely different story. After pulling 40-50 stands, the logger should become suspicious of the changing trends. The well actually started coming in between 40 and 60 stands. An alert logger should closely observe the well and should have the driller returned to bottom to condition the hole. Many blowouts occur during trips because a trip schedule is not made out or is not monitored in such a way to establish trends. Trying to kill a well off bottom leads to many associated well control problems, e.g. lost circulation, differential sticking, hole bridging... etc. Side tracking and hole problems associated with unscheduled deviated holes is normally the end result.

B. TRIP-OUT MONITORING PROCEDURES

Failure to keep the hole full while tripping can lead to serious problems; so, It is essential to properly monitor hole filling and trip trend to make sure that hole is taking the right amount of fluid replacing the metal volume being removed. Failure to keep the hole full while tripping can be considered as the single biggest cause for blowouts.

WET STRING	DRY STRING
Hole is to be filled with mud equal to both the metal displacement and pipe capacity.	Hole is to be filled with mud equal to the metal displacement only.
2- With “<u>Trip Tank</u>” in use (Cont. fill): Volume shows a decreasing trend equal to the metal displacement plus pipe capacity; then it shows an increasing trend equal to pipe capacity	2- With “<u>Trip Tank</u>” in use:(Cont. Fill): Volume will show a continuous decreasing trend.

only.	
3-With <u>Rig Pump</u> in use : An increasing trend while pulling out and a decreasing trend while filling hole (metal displacement + pipe capacity).	3-With <u>Rig Pump</u> in use : Volume will show no change while pulling out, and a decreasing trend while filling the hole.

What would a trip schedule tell you when pulling pipe out of the hole?

Stands (94 ft.)	Displacement		Time	Measured Trend Differences		
POH	Calculated (Cum)	Actual (Cum)	0100	Calcu- lated	Actual	Trend Change
1-10	6.7	8.0	0120	6.7	8.1	+ 1.4
11-20	13.4	16.0	0140	6.7	8.0	+ 1.3
21-30	20.1	24.1	0200	6.7	8.0	+ 1.3
31-40	26.8	31.6	0220	6.7	7.5	+ 0.8
41-50	33.5	38.6	0240	6.7	7.0	+ 0.3
51-60	40.2	45.1	0300	6.7	6.5	- 0.2
61-70	46.9	51.1	0320	6.7	6.0	- 0.7
71-80	53.6	56.1	0340	6.7	5.0	- 1.7
81-90	60.3	60.3	0400	6.7	4.2	- 2.5

If a logger looks at only volume (actual vs. calculated), everything might look good after POH with 90 stands. However, the trends tell a completely different story. After pulling 40-50 stands, the logger should become suspicious of the changing **trends**. The well actually started coming-in between 40 and 60 stands. An alert logger should closely observe the well and should have the driller returned to bottom to condition the hole. Many blowouts occur during trips because a trip schedule is not made out or is not monitored in such a way to establish trends. Trying to kill a well off bottom leads to many associated well control problems, e.g. lost circulation, differential sticking, hole bridging... etc. Side tracking and hole problems associated with unscheduled deviated holes is normally the end result.

Notes

7. Sample collection and description

30. Preparation for collection of cutting sample

The cuttings are physical, tangible pieces of drilled rocks which required the forces of nature millions of years to lay them down and, it cost the oil companies much time and millions of dollars to recover. Drilled cuttings are often referred to as “*Ditch Samples*”. The expression comes from early drilling rigs that used an earthen ditch to channel mud flow at the surface.

The cuttings samples can be in a span of just a few minutes either saved for an eternity or lost for ever. Aside from their immediate value, the cuttings can be saved and re-evaluated in the future using knowledge and techniques that have not been discovered yet. On the other hand cuttings falling into the reserve pit are cuttings gone forever along with the information they contain. An accurate lag, a source of representative samples and close attention to making efficient use of available time are all necessary to good cuttings and mud samples collection.

31. Shaker Samples

Almost every rig has shakers with vibrating screens for separating the cuttings from the mud as they reach the surface. The shaker screen should be examined to ascertain whether the mesh size is small enough to separate small cuttings from the mud.

When the shaker screen is used a board box should be placed at the foot of the screen for the collection of the cuttings through a complete interval of the hole. What is meant here is that the sample taken would be representative of the complete interval (10 feet, 30 feet, etc.) and not just cuttings coming across the shaker at some given time representing a spot check of a couple of inches.

The board box should be cleaned following each single sample gathering to avoid the mixing-up of samples of different intervals. The table on the following page will help to determine suitable screen sizes.

Particle type	Particle Size in millimeters	Tyler Screen Mesh Size
Silt	> 1/16	250
Very Fine Grain Sand	1/16 to 1/8	250 - 115
Fine Grain Sand	1/8 to 1/4	115 - 60
Medium Grain Sand	1/4 to 1/2	60 - 30
Coarse Grain Sand	1/2 to 1.0	30 - 16

Settling Box Samples

Although the shaker screen cutting sample interval method is the one most often used, another means of collecting samples is the Settling Box.

The Settling Box is however, far more satisfactory as a means of collecting cuttings samples than the shaker screen. Such a box is available from Houston stock. This box or a similar box should be rigged up in such a manner that a part of the mud from the flow line is diverted into it (through a two-inch line for example). The mud flows through the box and over a removable gate in the opposite end and into the mud pit. The reduced velocity of the mud permits the cuttings to settle on the bottom of the box.

After collecting a sample the gate must be lifted and the remaining cuttings are scraped and flushed out to prepare the box for collecting a sample from the next interval . The use of such a routine immures that a composite sample is collected for an entire interval of the hole and it affords the surest meant of collecting small cuttings and finely divided sand.

Such a box provides practically the only means of catching samples while the shaker is being bypassed. Establishing this sample-catching means beforehand will ensure that no quick improvisation will be encountered in the event that the shaker is bypassed and a uniform sample catching method will be assured throughout the hole.

Hint and Precautions

1. The discharge from the settling box go into the shaker pit or sand ditch.
2. A small stream of water added in the settling box will help settle cuttings in heavy viscous mud. Check with the tool pusher or mud engineer before adding such a stream of water.
3. A rapid change to little or no sample coming over the shaker can mean finely divided sand has been increase in this case.
4. The same problem can mean a salt section has been encountered. Check the salinity of the mud, and watch for deterioration of the mud characteristics.
5. Check the de-sander and de-silter discharges for the possible presence of sample material going through the shaker screens.

COLLECTING CUTTINGS SAMPLES

It is common for the Mudlog to be plotted on the basis of a sample interval of five feet or one meter. Obviously the number of tasks assigned to the logger and the amount of equipment he is required to operate will have a great beating on the frequency with which he will be able to catch the samples and therefore, the intervals at which he will plot the log. The logger should learn to work out a routine for himself which will allow to work at a high level of efficiency and to make provision for the collection of the important information in the time allotted him.

When circumstance does not permit the catching of the sample at exactly the set interval, some judgement comes into play, usually backed by experience which allows for a little leeway one way or the other of taking the sample.

This results in plotting an interpolated log which still describes the formation encountered. However, this manipulating of the schedule should not lead to the act of merely running back and forth to the shaker screen, catching samples and making

entries on the data sheet on the next entry line without paying due attention to the proper correlation with depth.

Without proper thought to what he is doing the logger can find himself in the situation of his own diligence not to miss a single sample, causing the depth correlation to become an utter chaos.

It is better to take a few less samples and be positive of their origin than not missing any but ignorant of what depths they all came from.

Take as many samples as possible and still make good correlation as to depth.

Collecting “Wet” Samples

This is a sample of unwashed cuttings that is taken for paleontological and petrological examination in the oil company's laboratories. It comprises a sample put straight into a fine mesh cloth bag, labelled and left to dry in the sun before tying into bundles and bagging up in labelled sacks or boxes. Care must be taken to adequately fill the sample sack or tin.

By operating company's request, wet samples are sometimes placed into plastic bags prior to being put into cloth sacks or tins. In this event a few drops of a bacteriacide solution such as formaldehyde or zephin chloride must be added to the prevent bacterial decay which can be initiated by some mud materials.

Washing Cuttings From Water-Base Mud

Washing and preparing The cuttings sample to be examined is probably as important as the examination itself. Here again, the technique must be adapted to the type of material and the area. In hard rock areas the cuttings are usually easily cleaned. Washing is usually just a matter of hosing the sample with jet of water to remove the film of the drilling mud from the surface of the cuttings.

Washing the cuttings from areas of recent geological ages is, however, a bit more difficult and requires the use of several precautions. As the shales present are soft and dispersible in water, the wash water will tend to wash this shale away. This should be taken into account; the mud logger should remain aware that the shale that would be washed away is a part of the sample and not a foreign material and should be logged accordingly. The sample should be washed no harder than necessary to remove the drilling mud.

Cuttings from zones of lost circulation are often intermixed with lost circulation material. This material will usually be floated out of the container.

After the cuttings have been washed for mud removal, they should be washed through a 5 mm sieve for the removal of sloughed shale and then into the 80 mesh sieve.

Following the sieving a portion of the washed sample is put onto one of the trays provided for the microscopic inspection and drained before use.

A larger sample is placed on another tray and dried into an oven before placing in an annotated envelope and boxed for the oil company analysis. The cutting should not be exposed to extra heating inside the oven as this could be burnt losing the original rock characters.

The tray for immediate examination should contain a single layer of cuttings only. This is important when considering relative percentages of different materials contained.

Cuttings in oil base muds

In the case of oil base mud cuttings are quite representative of the formations as this type of mud prevents sloughing, but at the same time, however, they pose a problem of washing and handling. They cannot be cleaned by washing in water alone, so it is necessary to use a detergent in order to clean them out.

For this purpose many of liquid detergents -commercially available- can be utilized.

Procedure:-

Set up two containers such as two halves of a 25 gallon drum. In one a non-fluorescent solvent, vestal or naphtha should be used for first washing the outer coating of oil and mud off the cuttings. In the other container mix solution consisting of one pint of a commercially available detergent to five gallons of water. Wash the cuttings in the detergent solution to remove the solvent, then they can be washed in water as usual. In order to make a good inspect for lithology and staining, the cuttings better be broken crushed.

32. Sample Descriptions

Sample Quality & Examination Techniques

The quality of a sample log is frequently a direct measure of the quality of the samples. Clean, good quality samples are exceptions rather than the rule.

The geologist logging samples must learn to make his interpretations from samples of widely varying quality. Cavings and other contaminants must be recognized and disregarded.

Many methods of examining samples are in use throughout the industry. Some geologists pour and examine one sample at a time; others lay out the samples in compartmented trays so that a sequence from five to ten samples may be observed in a single tray.

The following procedure is recommended:

- The samples are laid out in a stack of five-cell trays, with the depths marked on the trays.
- The cuttings should just cover the bottoms of the trays.
- It is sometimes desirable to separate the obvious cavings by either sieving or dry panning.
- Attention should generally be focused on the smaller cuttings with angular shape and fresh appearance.

A standard practice is to scan 100 or more feet of samples, observing the lithological “breaks”.

The samples are then re-examined for more detailed study, dry for porosity estimates and wet for all other properties.

Wetting the samples do not only cleans-off the mud and other contamination, but also brings out the rock characteristics that are not apparent in dry samples.

The tray should be dipped in a basin of water, agitated gently to remove any fine contaminants, and then removed and drained for study, leaving the samples still covered by a film of water.

After the cuttings have been logged, they are set aside to dry and then returned to the sample bags.

The technique of scanning samples before logging them in detail has many advantages. In addition to helping the examiner to pick the formations' tops and lithological breaks, it may also aid him in determining the extent of porous and hydrocarbon bearing intervals. However, the principal advantage of this technique is that it provides the geologist the opportunity to observe and interpret the depositional sequences.

When sample intervals are laid out in sequence subtle changes in texture, mineralogy, color and facies often become apparent even before the microscopic examination. Thus the observer is alerted to look for these changes when making the detailed examination. This method of examining samples, encourages geologists to observe and log the lithology rather than the sample interval units. It eliminates the laborious and time consuming task of routinely describing each sample interval. It increases speed of logging and it invariably helps the geologist make a more meaningful log.

Textures in carbonate rock can be clearly observed with the aid of special wetting agents such as mineral oil, glycerin, clove oil, etc.

Abbreviations

Abbreviations should be used for all descriptions recorded on lithological logs. These terms differ from an exploration company to another, so, it's of primary importance that the logger should ask for a list of abbreviations the company uses at the beginning of every new job.

Abbreviations for nouns are designated with capital initial letters; other terms are abbreviated entirely in small letters.

Order of Written Description

When written descriptions are required, a standardized order of description will help :

- (1) reduces the chance of not recording all important properties.
- (2) increases the uniformity of description among geologists.
- (3) saves time in obtaining specific information from descriptions.

THE FOLLOWING ORDER IS TO BE FOLLOWED:

- A. **For Clastic Rocks:-** Sand/sandstone/siltstone/clay/shale, etc.

First. Color

Second. Grain size, sorting then grain shape

Third. Hardness

Fourth. Cement and/or matrix materials.

Fifth. Fossils and accessories

Sixth. Sedimentary structures.

Seventh. Porosity and oil shows.

Example:

Sst: Lithic, bu-wh , f -med , mod srtd, ang ,occ/ sub ang, hard, arg , mica , pyr, fr
intgran por , gd stn , gd cut fluor.

II. For Non-Clastic Rocks:- Evaporites/limestone/dolomite/chert, etc.

First. Color.

Second. Crystallinity

Third. hardness.

Fourth. Cement and/or matrix materials.

Fifth. Fossils and accessories.

Sixth. Porosity and oil shows.

Example:

Ls: Wh, off wh, occ/ mlky wh, cryptoxln-microxln, md hd-hd, sli arg, , dol in pts, rr
foss, no vis por, no oil shows.

Rock Types

A proper recording of rock type, consists of two fundamental parts:

The basic rock name (underlined): e.g. Dolomite, Limestone, Sandstone, and the proper compositional or textural classification term: e.g., lithic, oolitic grainstone, etc.

Color

Color of rocks may be a mass effect of the colors of the constituent grains, or result from the color of cement or matrix, or staining of these. Colors may occur in combinations and patterns, e.g. mottled, banded, spotted, variegated. It is recommended that colors be described on wet samples under ten-power magnification. It is important to use the same source of light all the time, and use constant magnification for all routine logging.

General terms such as dark grey, medium brown, etc., generally suffice. However, if more concise designation is required, rock-color chart may be used.

Ferruginous, carbonaceous, siliceous, and calcareous materials are the most important staining or coloring agents.

Yellow red or brown shades come from limonite or hematite,.

Gray to black color can result from the presence of carbonaceous or phosphatic material, iron sulphide, or manganese.

Green coloring comes from Glauconite, ferrous iron, serpentine, chlorite and epidote.

Red or orange mottlings are derived from surface weathering or subsurface oxidation by the action of circulating waters.

The colors of cuttings may be altered, after the samples are caught, by oxidation caused by storage in a damp place, insufficient drying after washing or by overheating.

Bit or pipe fragments in samples can rust and stain the samples. Drilling mud additives may also cause staining.

Texture

Texture is a function of the size, shape and arrangement of the component elements of a rock.

1. Grain or crystal sizes:

Size grades and sorting of sediments are important attributes. They have a direct bearing on porosity and permeability, and may be a reflection of the environment in which a sediment was deposited.

The microscopist should better record size grades with reference to some standard comparator of mounted sieved sand grains or photographs of these.

Another simple and useful tool is a photographic grid of half-millimeter squares which may be fixed on the bottom of a sample examination tray.

2. Grain Shape

Shape of grains has long been used to indicate the history of a deposit of which the grains are a part.

Shape involves both *sphericity* and *roundness*.

A) Sphericity:

Refers to a comparison of the surface area of a sphere of the same volume as the grain, with the surface area of the grain itself. For practical purposes, distinction is usually made in large particles, on the basis of axial ratios and in grains.

B) Roundness

Roundness, which refers to the sharpness of the edges and corners of a fragment, is an important characteristic that deserves careful attention in detailed logging. Five degrees of rounding may be distinguished as follows :-

Angular :edges and corners sharp; little or no evidence of wear.

Subangular :faces untouched, but edges and corners rounded.

Subrounded :edges and corners rounded to smooth curves; areas of original faces rounded.

Rounded :original faces almost completely destr-oyed, but some comparatively flat faces may be present; all original edges and corners smoothed off to rather board curves.

Well Rounded :no original faces, edges, or corners remain; entire surface consists of broad curves. Flat areas are absent.

Sorting

Sorting is a measure of dispersion of the size frequency distribution of grains in a sediment or rock. It involves shape, roundness, specific gravity and mineral composition as well as size. A classification given by Payne (1942) that can be applied to these factor is:

Good	:	90% in 1 or 2 size classes
Fair	:	90% in 3 or 4 size classes
Poor	:	90% in 5 or more size classes

The terms; Well, modrately and ill sorted can be aso used to identify the above mentiond.

Cement and Matrix

Cement: is a chemical precipitate deposited around the grains and in the interstices of a sediment as aggregates of crystals or as growths on grains of the same composition.

Matrix: consists of small individual grains that fill intersections between the larger grains.

Cement is deposited chemically and matrix mechanically.

The order of precipitation of cement depends on the type of solution, number of ions in solution and the general geochemical environment.

Several different cements, or generations of cement, may occur in a given rock, separately or overgrown on or replacing one another.

Chemical cement is uncommon in sandstone which has a clay matrix. The most common cementing materials are silica and calcite.

Silica cement is common in nearly all quartz sandstones. This cement generally occurs as secondary crystal overgrowth deposited in optical continuity with detrital quartz grains. Opal, chalcedony and chert are other form of siliceous cement.

Dolomite and calcite are deposited as crystals in the interstices and as aggregates in the voids. Dolomite and calcite may be indigenous to the sandstone, the sands having been a mixture of quartz and dolomite or calcite grains, or the carbonate may have been precipitated as a coating around the sand grains before they were lithified.

Calcite in the form of clear spar may be present as vug, or other void filling in carbonate rocks.

Anhydrite and Gypsum cements are more commonly associated with dolomite and silica than with calcite.

Additional cementing materials, usually of minor importance, include **Pyrite**, generally as small crystals, **Siderite**, **Hematite**, **Limonite**, **Zeolites** and **Phosphatic material**.

Silt acts as a matrix, hastening cementation by filling interstices, thus decreasing the size of interstitial spaces.

Clay is a common matrix material, which may cause loss of porosity, either by compaction, or by swelling when water is introduced into the formation.

Argillaceous material can be evenly distributed in siliciclastic or carbonate rocks, or have laminated, lenticular detrital or nodular form.

Compaction and the presence of varying amounts of secondary quartz, secondary carbonate and interstitial clay are the main factors affecting pore space in siliciclastic rocks. While there is a general reduction of porosity with depth due to secondary cementation and compaction, ranges of porosity vary considerably due primarily to extreme variations in amounts of secondary cement. For instance, coarse grained sandstones have greater permeability than finer ones, when the same amount of cementing material is available to both. However, the same thickness of cement will form around the grains regardless of their size, therefore the similar intersections which occur in finer grained sandstones, will be cemented earliest.

Fossils and Accessories

Microfossils and some small macrofossils, or even fragments of fossils, are used for correlation and may also be environment indicators.

For aid in correlation, anyone making sample logs should familiarize himself with at least a few diagnostic fossils.

The worldwide Cretaceous foraminiferal marker, *Globotruncana*, for example, should be in everyone's geologic "vocabulary."

Any geologist who examines samples, should be able to distinguish such form as foraminifera, ostracods, chara, bryozoa, corals, algae, crinoids, brachiopods, pelecypods and gastropods, so as to record their presence and relative abundance in the samples being examined.

More detailed identification will probably have to be made with the aid of the literature, and/or the advice and assistance of a paleontologist.

An excellent reference for the identification of the more common microfossils is "Recognition of Invertebrate Fossil Fragments in Rocks and Thin Sections", by O. P. Majewske (1969).

Fossils may aid the sample examiner in judging what part of the cuttings is in place and what part is caved. For example, in the Gulf Coast region, fresh, shiny foraminifera, especially with buff or white color, are usually confined to Tertiary beds; their occurrence in samples from any depth below the top of the Cretaceous is an indication of the presence of caved material.

It would be helpful to each sample-logger to have available one or more slides or photographs illustrating the principle microfossils which might be expected to occur in each formation he will be logging.

Accessory constituents

Although constituting only a minor percentage of the bulk of a rock, may be significant indicators of the environment of deposition, as well as clues to correlation. The most common accessories are glauconite, pyrite, feldspar, mica, siderite, carbonized plant remains, heavy minerals, chert and sand-sized rock fragments.

Sedimentary Structures

Most sedimentary structures are not discernible in cuttings. On the other hand; one or more of them can always be found in any core and they should be reported in the description thereof.

Structures involve the relationship of masses or aggregates of rock components. They are conditioned by time and space changes; e.g. stratification may result from discrete vertical (time) change in composition, as well as changes in grain sizes or of fabric.

In time of origin, they are formed either contemporaneously with deposition (syngenetic), or after deposition and burial (epigenetic). Syngenetic structures are often very important indicators of the environments of deposition of sediments.

Porosity

Among the most important observations made in the course of sample examination, are those relating to porosity. Porosity is a measure of the volume of void spaces in a rock. The ability to estimate an accurate porosity, comes through practice and experience in examining samples. Although the magnification of about 10^x is adequate to detect porosity, higher magnification is often necessary. Pores are easier to recognize in dry samples than in wet ones.

If porosity of any category is observed, it should be thoroughly described, and additional comments should be made in the remarks column.

Samples with porosity, should always be checked for hydrocarbons, regardless of whether or not staining is observed, high gravity oils may leave little or no staining on the rock surface.

In siliciclastic rocks, three types of porosity are common: intergranular, moldic and fracture. The intergranular is the most common type and most rapidly seen in cuttings, others are difficult to recognize in cuttings.

In carbonate rocks, porosity is always classified in one of the following categories: interparticle, intercrystal, vuggy, moldic and fracture.

A number of classifications considering various aspects of carbonate porosity and permeability have been developed, including those by P. W. Choquette and L. C. Pray (1970) and by G. E. Archie (1952).

Hydrocarbon Shows

The primary objective of any exploratory well is to discover oil or gas in commercial quantities. Therefore, it is vital to continuously analyze both the drilling fluids and sample cuttings for hydrocarbons. The geologist and mud logger are required to make a detailed lithological description of the drilled section, which is used to evaluate the

area for future drilling, particular emphasis is placed on the analysis or hydrocarbon shows.

NB: A show is an indication of hydrocarbons in a formation. Porosity and productivity is only a factor in how good the show is.

BASIC TERMS:

HYDROCARBONS..A compound containing the two elements hydrogen and carbon.

PETROLEUM.....A material occurring naturally in the earth, composed of mixtures of compounds of carbon and hydrogen with or without non-metallic elements such as sulphur, oxygen, nitrogen etc. Petroleum may contain such compounds in the solid, liquid, and/or gaseous state, depending on temperature and pressure.

OIL..... Petroleum in the liquid state, normally called crude oil.

CONDENSATE.... Those liquid hydrocarbon mixtures which are gaseous in the reservoir, but are recoverable in the liquid state at the surface.

NATURAL GAS... A mixture of gaseous hydrocarbons found naturally.

WET GAS:Natural gas which contains more than 0.3 gallon of condensate per 1,000 cubic feet of gas.

DRY GAS:Gas containing less than 0.1 gallon of condensate per 1,000 cubic feet.

SOLID PETROLEUM: general name for various solid or semi-solid hydro- carbon mixtures such as bitumen, asphalt, residuum, etc.

The table overleaf lists the paraffin series of hydrocarbon compounds, the most common ones that can be identified at the wellsite are:

METHANE	ETHANE	PROPANE	N-BUTANE	ISO-BUTANE	PENTANE
CH₄	C₂H₆	C₃H₈	C₄H₁₀	C₄H₁₀	C₅H₁₂

OIL STAINING

Rocks which obviously contain oil can be observed under the microscope as the cuttings are stained with oil. The percentage of specific rock type exhibiting staining should be noted. The colour and-degree of oil stain is similarly recorded.

FLUORESCENCE

The sample tray should be placed in the UV-Box and checked for fluorescence, the colour and degree of fluorescence is noted. There are frequently several different colours of fluorescence in a sample, so a few pieces of each colour should be picked out and isolated on a spot dish for the chlorothene test.

Chlorothene test: when a solvent, such as chlorothene is added to the sample, oil will visibly be leached out and will dissolve in the solution turning it a yellow or brownish colour. The degree of 'cut' (slight, strong etc.) and its colour is described. The sample is next placed under UV-Box light and the degree of cut fluorescence is observed. When the solvent has evaporated, a fluorescent residual ring forms around the edge of the spot dish indicating 'live oil', the colour of this ring under UV-Box light is noted as

colour of cut fluorescence, The degree of cut or ability of oil to flow out depends primarily on the permeability of the rock, taking into consideration the factor of, quantity of oil. In a permeable, oil bearing rock the oil will flow out when placed in chloroethene. The oil will stream out and is therefore, termed a 'streaming cut', less permeable rocks, however, will cut more slowly, gradually turning the solvent a milky colour (usually yellow). In tight rocks with low permeability only a very faint cut or perhaps none at all is observed. This type of rock should be crushed with a clean instrument while it is in the spot dish filled with solvent, The solvent will then turn a milky colour and a fluorescent ring be left on the dish.

Note: If there is no visible oil staining, fluorescence, cut or cut fluorescence in an otherwise potential reservoir then, this fact should be noted in the sample description.

33. DESCRIBING AND LOGGING OIL SHOWS

A. Degree of oil stain

1. No visible oil stain
2. Spotty oil stain
3. Streaky oil stain
4. Patchy oil stain
5. Uniform oil stain

B. Colour of oil stain

1. No visible oil stain
2. Light brown oil stain
3. Medium brown oil stain
4. Dark brown oil stain
5. Black asphalt residue (dead oil)

C. Degree of oil fluorescence

1. No visible oil fluorescence
2. Spotty oil fluorescence
3. Streaky oil fluorescence
4. Patchy oil fluorescence
5. Uniform oil fluorescence

D. Colour of oil fluorescence

1. No visible oil fluorescence
2. All shades of blue
3. All shades of yellow
4. All shades of gold
5. All shades of brown

E. Degree of cut

1. Excellent
2. Strong
3. Moderate
4. Slight
5. Very slight

F. Colour of cut

1. All shades of Yellow
2. All shades of brown

G. Degree of cut fluorescence

1. Instantaneous
2. Fast
3. Streaming - poor, fair, good.
4. Slow.
5. Crush- poor, fair, good.

B. Colour of cut fluorescence

- | | |
|---|------------|
| 1. Bright (colour) residual ring | - live oil |
| 2. Medium (colour) residual ring | - live oil |
| 3. Dull (colour) residual ring | - live oil |
| 4. Dark brown or black non-fluorescent ring | - dead oil |

- EXAMPLE:

SS: CLR-WH, F-MGN, MOD SRT, SBANG,HD, W/CAIC CMT, HI GLAUC, FRI, GD POR, W/ 50% STK, LT BRN O STN, STK,BRI YEL FLU, STRG YEL STRM CUT, BRI YEL RING.

= **Sandstone:** Clear to white, fine to medium grained, moderately sorted, subangular, hard, with calcareous cement, highly gluconitic, friable, good porosity, with 50% streaky, light brown oil staining, streaky, bright yellow fluorescence, strong yellow streaming cut, bright yellow ring.

NOTES Of CAUTION

1. Many rocks, notably Limestone and dolomite, exhibit mineral fluorescence, it is important to distinguish this from oil fluorescence. When solvent is placed on cuttings showing only mineral fluorescence, nothing happens - the Solvent remains clear, and no fluorescent residual ring is left on the dish after evaporation.

2. Care should be taken not to confuse oil staining with contamination of sample by pipe dope, rig grease or fluorescent mud additives. If in doubt, contamination should be checked under UV light for comparison.

3. Before using chlorothene to determine oil shows, check the solvent for contamination. Pour some onto a clean spot dish and allow evaporation. If a fluorescent ring forms then it is contaminated and should be discarded immediately to avoid logging false oil shows.

4. Before a spot dish is used it should be checked for contamination. under UV light. The correct method of cleaning a spot plate is to wash it with powdered soap, rinse it thoroughly to remove soap, and stand on end to allow evaporation of water. (soap and some towel fibers exhibit fluorescence).

5. Chlorothene must be stored or transported in glass bottles with bakellite tops and foil liner, or in tin cans for larger quantities.

For sample analysis, chlorothene should be kept in glass bottles with glass stoppers. Plastic containers, and rubber stoppers and droppers will eventually dissolve and contaminate the chlorothene, therefore, they should not be used.

6. Oil shows can be evaluated in oil base mud especially with cores. Ditch cuttings of lower permeability oil bearing rocks can also be noticed, regardless of the mud system by carefully searching with the fluoroscope for contrasts between the fluorescence of the oil mud and that of any natural oil.

DEFINITION OF TERMS

Several of the common terms which are normally found in descriptions of shows may carry different meanings for the person who wrote them than for the person reading them.

An attempt at standardizing definitions is made here.

One.STAINING: The color added to a rock by oil or organic material remaining in pores or coating the grain surfaces. This color must be described independently of the background color of the rock, which is a composite color compared of the colors of the various minerals which make up the rock.

Two.FLUORESCENCE: The ability of the oil on or in the cuttings to absorb ultraviolet rays and give off visible light. Care must be taken to ensure that the fluorescence reported for a show is a hydrocarbon fluorescence and not caused by minerals.

Three.CUT: Solubility of the oil in the sample. A cut is obtained by exposing cuttings to a solvent such as chlorothene or carbon-tetra-chloride. This cut fluorescence is the estimated amount of fluorescing material that streams from the sample as observed under fluorescent light, or the fluorescent ring remaining on the dish after the solvent has completely evaporated,

Four.LIVE OIL: Oil which has a high percentage of volatile (gas) in solution to that it is mobile in the reservoir.

Five.DEAD OIL: Oil in the reservoir which has little or no gas in solution.

Six.RESIDUAL OIL: Particulate oil in a sample Which generally occurs as black particles disseminated throughout the smaller pores of the sample. Residual oil may be bitumen, pyrobitumen or biowaxes.

Seven.BITUMEN (Asphalt-Tar): A generic term applied to most natural inflammable substances composed principally of a mixture of hydrocarbons substantially free of its volatile compounds. It generally occurs in samples as a heavy, viscous, semi-solid black residue. Bitumen will not exhibit any visual fluorescence under fluoroscope, but its cut may do. It can be dissolved by benzene, chloroethene and carbontetrachloride. Bitumen melts and flow at temperatures above 130 F.

Eight.PYROBITUMEN: A material resembling bitumen, but composed primarily of carbon. It exhibits no fluorescence or cut and it is totally insoluble in any solvent. As opposed to bitumen, it only melts at very high temperatures

BIOVAXES: When an oil is attacked by bacteria, the ending product is an unusual high-melting wax This biowax is black (due to asphaltnes), has no fluorescence and insoluble. The physical appearance may be similar a hand black shoe polish. Visually, one may have difficulty distinguishing between pyrobitumen and biowaxes in rock samples.

Distinguishing "live" oil from "dead" oil

A highly interpretative method of defining Live from Dead oils is as follows:-

To determine whether live oil occurs, the cuttings are put in a dish of water, placed under an ultraviolet light and viewed through a microscope while crushing the Samples. This operation is best performed by using a "Corvascope".

The data obtained by use of this method in conjunction with such parameters as staining, fluorescence and cut can then be combined to distinguish between the two types of oil.

A) When the oil moves rapidly to and spreads onto the surface of water; it is live oil trapped in the smaller pores of the cuttings.

B) If the oil moves slowly out of the cutting but Still spreads on the surface; it is live oil occurring in a tight rock.

C) Oil which moves slowly to the surface and does not spread but remains in droplets, is dead oil.

D) No oil moves from the crushed cuttings:-

1- **Gas** - light to no stain, weak fluorescence, no cut

2- **Live oil - water-wet** - high porosity and permeability, light stain, fluorescence and cut, flushed and gas expansion,

3- **Bitumen** - dark stain and cut.

4- **Pyrobitumen and biowaxes** - black stain, no fluorescence or cut.

OIL FLUORESCENCE (AFTER LYNCH)

A.P.I. GRAVITY	COLOUR
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BELOW 15 °	BROWN
15 ° - 25°	ORANGE (GOLD)
25° - 35°	YELLOW / CREAM
35° - 45°	WHITE
Over 45°	BLUE / WHITE /. VIOLET

Miscellaneous tests For hydrocarbons

1st.Acetone Test

The sample is washed slightly and dried naturally. About 10 cc. of sample is placed in a test tube.and 20-30 °C of pure acetone is added. After mixture is shaken, 20-30 cc. of distilled water is added If oil is present, the liquid turns milky This is ; test is a delicate one and it is not advisable to run as final check ; if the test is positive; it's not a proof of hydrocarbon content, but the negative result assures the absence of hydrocarbons.

2nd.Heat Test

Place about 10 cc. of sample in a Pyrex test tube, hold the test tube at a 45° angle and heat the sample over an open flame. If hydrocarbons are present, they will they well condense up the tube. Test the condensate with solvents and ultraviolet light: This is a DANGEROUS TEST and should with extreme caution.

3rd.Hot Water Test

Place 20-30 cc. of sample in a clean baker and completely cover with hot water (167°F or 75°C). Allow the mixture to stand for several minutes. If oil is present, it will be released from the rock and float to the surface of the water. Check with the ultraviolet light and solvents

4th.Acid Test

This test is only valid for carbonate reservoir rocks. Place a quantity of 10% HCL hot acid in a test tube and drop a cutting into the tube. If the cutting contains oil it will bounce on the acid and often leaves an oil residue on the wall of the test tube. Check this oily residue for fluorescence and cut. This is not a very accurate test but it serves as an indicator of hydrocarbons and should be followed by more analytical tests.

34. Some Criteria & Procedures For Rock & Mineral Identification

Testing Methods:

Tests with Dilute HCL (10%)

There are different types of observations to be made on the results of treatment with 10 % dilute acid:

a) Degree of effervescence:

Limestone and Dolomite determination are characterised by effervescence values arrived at by the use of 10 % hydrochloric acid, Pure limestone effervesces violently while pure dolomite will not effervesce at all in cold 10 % acid. Dolomite will effervesce slowly if heated in the acid.

These components are seldom encountered in a pure state, as usually they are mixtures of one or other predominating or either one mixed with shale. For example, it might be debatable whether to call a material shaley limestone or limy shale. One procedure by which to arrive at a standard for making the distinction is as follows:-

Place several pieces of material in a depression of the spot plate and cover with 10 % HCL.

If it begins to effervesce immediately the material is probably limy than dolomitic. Warm the spot plate add acid and let it effervesce until additional acid will create no more effervescence. If the cuttings still regain their original general shape, they were limy shale : if they no longer have their original shape but only appear as a residue left behind the limestone was predominant and the cutting were Shelly lime.

Impurities slow the reaction, but these can be detected in residues. Oil-

stained limestones are often mistaken for dolomites, because the oil coating the rock surface prevents acid from reacting immediately with CaCO_3 , and a delayed reaction occurs. The shape, porosity and permeability will affect the degree of reaction, because the greater the exposed surface, the more quickly will the reaction be completed.

b) Nature of residue:

Carbonate rocks may contain significant percentages of chert, anhydrite, sand, silt or argillaceous materials that are not readily detected in the untreated rock fragments.

Not all argillaceous material is dark colored, and, unless an insoluble residue is obtained, light colored argillaceous material is generally missed. During the course of normal sample examination in carbonate sequences, determine the composition of the noncalcareous fraction by digesting one or more rock fragments in acid and estimate the percentage of insoluble residue. These residues may reveal the presence of significant accessory minerals that might otherwise be masked.

c) Oil reaction:

If oil is present in a cutting, large bubbles will form on a fragment when it is immersed in dilute acid.

Hardness

Scratching the rock fragment surface is often an adequate way of distinguishing different lithic types. Silicates and silicified materials, for example, can not be scratched, but instead will take a streak of metal from the point of a probe.

Limestone and dolomite can be scratched readily, gypsum and anhydrite will be grooved, as will shale or bentonite.

Weathered chert is often soft enough to be readily scratched and its lack of reaction with acid will distinguish it from carbonates.

Caution must be used with this test in determining whether the scratched material is actually the framework constituent or the cementing or matrix constituent. For example, silts will often scratch or groove, but examination under high magnification, will usually show that the quartz grains have been pushed aside and are unscratched and the groove was made in the softer matrix material.

Parting (Fissility)

Shaly parting, although not a test, is an important rock character. The sample logger should always distinguish between shale, which exhibits parting or fissility and mudstone, which yields fragments which do not have parallel plane faces.

Slaking and Swelling

Marked slaking and swelling in water is characteristic of montmorillonites (Shale rich in bentonite) and distinguishes them from kaolinite and illites.

Thin Sections

Certain features of rocks may not be distinguishable, even under the most favorable conditions without the aid of thin sections.

Thin sections adequate for routine examination can be prepared without the use of the refined techniques necessary to produce slides suitable for petrography study.

Some of the questions of interpretation which might be clarified by the use of thin sections, include the following:-

mineral identification, grain-matrix relationships, grain-cement relationships, pore space relationships and distribution, grain sizes, source rock quality.

Although wetting the surface of a carbonate rock with water, or mineral oil, permits "in depth" observation of the rock, some particles, or particle-matrix relationships still remain obscure until the rock is examined by transmitted light, plane and/or polarized.

Once these features have been recognized in thin sections, they are frequently detectable in whole fragments, and only a few thin sections may be needed in the course of logging a particular interval. It is important to have polarizing equipment available for use in thin section examination - many features of the rock texture, and some minerals, are most readily recognized by the use of polarized light.

Staining Technique for Carbonate Rocks

The distinction between calcite and dolomite is often quite important in studies of carbonate rocks. For many years several organic and inorganic stains have been used for this purpose, but with varying degrees of success.

Friedman (1959) investigated a great variety of stains for use in identifying carbonate minerals. He developed a system of stains and flow charts for this purpose.

These vary in ease of application, but most are not practical for routine sample examination.

The reader is referred to Friedman's paper for an extensive discussion of carbonate mineral stains.

One stain that is applicable to routine sample examination and is both simple and rapid is “*Alizarin Red S.*” This stain can be used on any type of rock specimen, and it has proved especially useful in the examination of cuttings.

The reactions to acid of chips of dolomitic limestone or calcareous dolomite are often misleading, and the rapid examination of etched chips does not always clearly show the calcite and dolomite relationships.

Alizarin Red S. shows clearly the mineral distribution. Calcite takes on a deep red color; other minerals are uncolored.

Heavy Mineral Studies

Heavy mineral studies are used today, primarily when a geologist is seeking information concerning the source areas and distribution patterns of siliciclastic sediments. Their use as a correlation tool is limited. Excellent descriptions of techniques are available in the literature.

Tests for Specific Rocks and Minerals

Many of the more perplexing problems of rock mineral identification can be solved by the use of thin sections. However, certain simple and rapid tests are discussed as follows:

Clay

Shales and clays occur in a broad spectrum of colors, mineral composition and textures.

Generally, their identification is done with ease; however light colored clay or kaolinite is commonly mistaken for finely divided anhydrite.

The two may be distinguished by simple tests:

- i) Anhydrite will dissolve in hot dilute hydrochloric acid, and when cooled, will recrystallize out of solution as acicular needles. Clay remains insoluble in the hot dilute acid.
- ii) Barium Chloride BaCl_2 test: anhydrite dissolved in hot dilute acid will get turbid with drops of Barium Chloride solution and a white precipitate will deposit on the bottom of the test tube.

Chert

Recognition of the more common varieties of chert and siliceous carbonates, generally is not a problem.

Weathered chert, however, is often found to be soft enough to be readily scratched and mistaken for clay or carbonate.

Lack of reaction with acid, generally distinguishes this type of chert from carbonates.

Clay and tripolitic chert may require petrography techniques for differentiation. In thin sections under polarized light, chert commonly has a characteristic honey-brown color.

Evaporites

a) Anhydrite and Gypsum

They are usually readily detected in cuttings. Anhydrite is more commonly associated with dolomites, than with limestones, and is much more abundant in the subsurface than gypsum. At present, there appears to be little reason to distinguish anhydrite from gypsum in samples. Anhydrite is generally harder and has a pseudo-cubic cleavage; the cleavage flakes of gypsum have “swallow-tail” twins. Anhydrite can be readily recognized in thin sections by its pseudo-cubic cleavage, and, under polarized light, by its bright interference colors.

The dilute hydrochloric acid test is a valid and simple test for anhydrite or gypsum in cuttings. Place the cutting(s) in a watch glass and cover with acid.

Heat on a hot plate to $250^{\circ}\text{F} \pm (120^{\circ}\text{C} \pm)$ and wait for the sample to start dissolving. If anhydrite or gypsum is present, acicular gypsum crystals will form around the edge of the acid solution as it evaporates. If the sample contains much carbonate, a calcium chloride paste may form and obscure the acicular gypsum crystals. Dilute the residue with water, extract and discard the solution and repeat the test.

*A simple method of distinguishing finely divided anhydrite from silt is a scratch test. This can be done by two methods:-

- A. Rub glass rod on residue in bottom of glass test plate and listen for gritty sound.
- B. Place a drop of liquid containing the residue on a glass cover slip and cover with another slip. Rub them together between thumb and forefinger. Examine slips under microscope for scratch marks, or listen for gritty sound.

b) Salts

Are rarely found at the surface and generally do not occur in well samples. Unless salt-saturated or oil-base mud is used, salt fragments or crystals dissolve before reaching the surface. The best criteria for detecting a salt section are:-

- While clastics (sands/shale's) and carbonates (limestone's/dolomites) tend to drill at irregular ROP's evaporites generally drill at a fairly uniform rate.
- Chloride content of the drilling mud will increase and the fluid will tend to flocculate (get very viscous).
- Cuttings returns at the shale shaker will be minimal but may indicate small amounts of carbonate material as it is commonly found in association with evaporates.
- A sudden influx of abundant caved material in the samples.
- A sharp increase in drilling penetration rate.

Salts are commonly associated with cyclical carbonate sections and massive red bed sequences. In the former, they are usually thin bedded and often occur above anhydrite beds. Potassium-rich salts, the last phase of an evaporation cycle, are characterized by their response on gamma ray log curves.

Phosphate

Place on the suspected mineral (either on the hand specimen or on an uncovered thin section) a small crystal of pure white ammonium molybdate.

Allow one or two drops of dilute nitric acid to fall on the crystal.

If the rock contains phosphate, the crystal rapidly takes on a bright yellow color.

Feldspar

The presence, quantity and type of feldspar constituents can be important in the study of reservoir parameters in some sandstones. Feldspars are usually characterized by variable colours and angular edged particles.

Bituminous Rocks

Dark shales and carbonates may contain organic matter in the form of Kerogen or Bitumen. Carbonates and shales in which the presence of bituminous matter is suspected, should be examined by thin section and pyrolysis-fluorometer methods for possible source rock qualities. Dark, bituminous shales have a characteristic chocolate brown streak which is very distinctive.

35. GENERAL REMARKS ON SAMPLE DESCRIPTION

1. The major changes in the formations should be noted and the appearance of new formation material should be described as carefully as possible.
2. The logger upon coming on duty should familiarise himself with the samples from formations drilled while he was off-duty. This will aid him in spotting cavings and changes of formation characters.
3. In some cases the sample retrieved will not represent the formation at all. For example, evaporites sections drilled with a fresh water base mud will dissolve the formation salts as they rise in the annulus. In this case the previously mentioned criteria should be borne in mind.
4. In arriving at the geological descriptions of the formation drilled, such things as drilling rate and present depth of the bit should be taken into consideration. At fairly deep depths there is a tendency for cutting from a formation to become dispersed along the mud column and straggling out sometime after the formation has been drilled through. For instance after a sand has been drilled through, cuttings from this sand may continue to appear in samples for time.
5. Always bear in mind that contamination of an interval's cutting can occur for several reasons and must be excluded from the description.

36. CONTAMINATION OF CUTTINGS

Contamination of the cuttings is a direct result of the rig operations. Setting of casing, the mud additives, or any hole problems like pipe stuck, etc..., can all lead to a cuttings contamination. Contamination may or may not be easily detected. This depends on the logger's experience.

Below is a chart identifying some of the more common contaminants:-

TYPE	SOURCE	MISTAKEN FOR	CHARACTERISTICS
Mica	lost circulation material	a mineral that has been broken away from the rock	much larger flakes than found in most rocks, thick block (may layers), colourless or transparent in thin sheets, yellow or brown in thick blocks.
Lignite	thinners or dispersants	natural lignite or coal	lighter than cutting, reacts with water to give a slight coloration , brownish to black in colour, usually floats on water
Cement	Cementing casing pipe or cement plugs	calcareous siltstone, limestone	medium gray to white with black specks calcareous reacts with phenolphthalein and turns purple
Plastic beads	torque reducer	well rounded sand	transparent well rounded well sorted medium grain, lighter than water
Seed husks	lost circulation material	-	looks just like seed husks
Walnut hulls	lost circulation material	dark brown siltstone	lighter than cuttings and heavier than water so when it is agitated with water the rock cuttings will remain in place and the walnut hulls will move with water, light to dark brown with a distinct darker coloration on the surface, unique texture (detected by chewing)
Rubber	displacement plugs used in cementing (drilled out)	-	red or black rubber
Metal filings	from drill bit or pipe	-	metallic when fresh but may look like red siltstone or limonite when oxidized

U.V Box Contamination

When using the UV box, one must be certain that they are actually looking at a hydrocarbon bearing rock. There have been cases of false oil shows turned in due to practical jokes. Here is a list of a few common contaminants.

Type	Colour	characteristics
Pipe dope	bright blue	will cut using chloroethene
coffee grounds	dull green	with not cut
Some oil base mud additives	variety of colours	most will cut when using chloroethane.

8. GAS SYSTEM

- * **Factors affecting size of the gas show .**
- * **Types of recorded gases.**
- * **Gas detection system**
- * **Gas trap**
- * **FID gas detector**
 - Operating principle
 - Out put of the system
 - Advantages of FID system
 - FID gas chromatography
 - FID gas detector
 - FID gas chromatograph

General factors affecting the size of a gas show:

- 1– Amount of hydrocarbons present in the formation.
- 2– Type of hydrocarbons present
- 3– Porosity and permeability of the formation.
- 4– Mud weight overbalance (or underbalance) and amount of flushing.
- 5– Mud flow rate.
- 6– Mud properties, specifically viscosity.
- 7– Mud temperature.
- 8– Mud type in use.
- 9– Hole size.
- 10–Rate of penetration.
- 11–Type of bit ;affecting size of cuttings and amount of cuttings gas released into the mud.
- 12–Efficiency of gas trap, sample line and gas detectors.

37. Gas Curve

The amount of gas that enters mud as it passes through the system is recorded on one channel of the chart recorder against time. These gas values are converted to a gas curve against depth by use of the lag for plotting on the log.

The recorded amount of gas passes through several processes before being detected.

Gas enters the wellbore through two primary mechanisms. First it may be in the pore spaces of the rock being drilled, this gas is released by the bit and is known as liberated gas.

Second, it may be pushed into the wellbore by the pore pressure called produced gas, and it may come from any depth unlike liberated gas which only comes from the bit face.

Wells are normally drilled with an amount of differential pressure i.e the hydrostatic pressure exceeds the pore pressure. Adding the annular pressure drop to the hydrostatic pressure then we have the Equivalent circulating density (ECD). This means that there is an amount of considerable forces above the hydrostatic pressure exerting on the rock ahead the bit. This force drives mud filtrate into the rock at the bit face flushing the rock of any fluid that may be originally present. Core analysis data indicates that 90 - 95 % of the formation fluid is usually flushed away.

The feature commonly called “*Background*” may come from two sources.

The First source is, it is a produced gas from up the hole. Many shales are drilled underbalance allowing small quantities of gas to continually bleed into the wellbore from these low porosity, low permeability formations.

The second source is, “*Recycled Gas*”; Not all the gas that enters mud is removed by the surface equipment and some of it will be recycled through the hole. It may be distributed through the entire mud volume and be seen as a constant reading background. Or, it may be in varying concentrations causing varying readings on the gas detector. If this is the case; so then the recycled peak should occur at a delay equal to the time required for a complete Pit to Pit- circulation of the system (including the active pit volume). Recycled gas tends to be the less volatile components; heavy components of the hydrocarbon series as these are harder to be removed by the surface equipment.

Gas that is not strictly produced or liberated can also be seen. This is gas that is retained in the cuttings after they have been removed from the rock face and due to expansion, separates itself from the cuttings at some depth up the hole This can cause gas shows to spread out after the gas lag giving an exaggerated value to the show.

The mud composition can interfere with the gas response by holding certain portions of gas affecting either the volume of the gas released and/or the nature of the gas released. As an example; as the mud weight or salinity increased so the ability of the mud to dissolve gas decreases and the quantity of gas released increased.

In oil based mud (OBM) the solvent for gas is the oil phase, which has a much higher dissolution capacity than water so gas shows will be lower. The oil also has a greater

affinity for the heavier hydrocarbons so that the “heavies” may not be seen at the surface.

Apart from the varied capacity of mud to dissolve gas, the physical characteristics of the mud can enhance or reduce the size of a gas show. The lower the mud viscosity, for example, the more efficient the gas trap, the higher the gas shows.

Natural gas is a hydrocarbon gas composing of methane(CH_4) and its homologues($\text{C}_n\text{H}_{2n+2}$).

Natural gases also often contain small amounts of carbon dioxide (CO_2) hydrogen sulphide (H_2S) and nitrogen (N_2) At normal temperature and pressure.

Natural gases are always present in oil pools in the dissolved state while in some cases they evolve over the oil in the free state. This is the so called “Associated Gas” which is produced together with the oil.

This natural gas recorded while drilling is given different specific definitions according to the conditions associated to its appearance. On the coming pages we will go through these definitions.

38. TYPES OF RECORDED GASES

1) Cuttings gas (formation gas)

It is the gas liberated from the drilled cuttings enters the wellbore mud. These are the gases continuously recorded and plotted against depth and used to represent the formation content. There are some factors that control the size of this formation gas shows.

Factors affecting the size of the gas show:

- 1st)Rate of penetration; **ROP**
- 2nd)Differential pressure; **P**
- 3rd) Porosity ; **Ø**
- 4th)Hole size; **G**
- 5th) Flow rate; **Q**
- 6th)Depth; **ft or mtrs**

The **ROP** controls the concentration of gas in the mud for a given flow rate and is therefore the primary factor causing a variation of gas readings.

The **P** and **Ø** control the degree of flushing.

The hole size is **G** an important factor affects the size of the gas show, the larger the hole size, the more the cuttings, the more the gases liberated from these cuttings entering the mud.

The **Q** affects the gas concentration but as the flow rate is usually constant for a bit run this is not as important factor as a change in ROP.

As the **Depth** increases the gas shows should increase due to the increase of expansion that occurs.

2) Background gas

Under normal drilling conditions, it is common for a relatively small amount of gas to be continuously in evidence. This “background gas” can originate from a previously drilled section, which contained a show and bleeds an amount of gas into the mud.

Background gas is often methane with little or no wet gas. However, continuous high levels of background gas often suggest that the well is being drilled very close to balance (formation pressure is very close to mud head) and may indicate that a greater mud weight is required.

3) Trip gas

It is quite common for an increase in the mud gas reading to occur at the first bottom’s up circulation after a trip has been made. This occurrence referred to as “trip gas”.

In the process of “coming out of the hole”, the bit is being pulled through a mud filled cylinder of a diameter only slightly greater than the bit itself. As the bit is pulled through this cylinder formed by the hole wall, a swabbing action on the formation takes place and a momentary reduction in hydrostatic pressure occurs as bit is travelling upward. This enables the formation pressured gases to bleed into the hole each time the string is moved up. The resultant is an accumulated amount of gas at the bottom of the hole.

The amount of this gas depends on the following:-

One)Differential Pressure (Mud Weight / Formation Pressure)

Two)Pipe Movement Speed

Three)Mud Properties; viscosity

Four)Annular Size

Under normal conditions trip gas will be indicative of increasing formation pressure especially when the amount of trip gas increases with depth and each successive trip.

4) Connection gas

Similar to the trip gas, a connection gas may appear at the first bottom’s up circulation after a connection has been made. The reason of this is the reduction of the hydrostatic head when pumps are shut-off losing the effect of the E.C.D, along with the upward pipe movement that causes another negative swabbing pressure. This connection gas is used as a helpful guide towards drilling situation.

4) Circulation gas

Is the gas being liberated into the borehole when actual “hole making” is stopped and the mud is circulated with the bit on bottom. The purpose of this practice is to get an idea of the degree of underbalanced at that particular depth interval.

- **Miscellaneous gases:**

Kelly gas

Results from air trapped in the drill string during a connection. It can be easily identified by the time of its appearance relative to the time of connection and the pump rate to get this gas down the drill pipe up the annulus.

Carbide gas

Is caused by the mud logger putting a specified amount of carbide in a dissolvable package into the drill pipe at the time a connection is made. This carbide reacts with the mud and creates an acetylene that is a check for the time required to pump cuttings off bottom to the surface; lag check.

39. GAS DETECTION AND ANALYSIS

MONITORING EQUIPMENT

- **Gas Trap Assembly**

Continuously operating explosion proof, electrically powered degasser for breaking-out entrapped gases from mud.

- **Total Gas Detector**

Computer interfaced flame ionization detector which analysis a continuous stream of gas and air drawn from the gas trap, for total hydrocarbon gases. Accuracy to 1 unit (0.03%).

- **Gas chromatograph**

Computer interfaced, programmable flame ionization baseline chromatograph with automatic sampling and calibration for detection of hydrocarbons gas components, C1, C2, C3, C4, iso & normal, and C5.

Samples are either taken from the gas trap or by manual injection from the steam still.

- **steam still**

It is an equipment used to measure the hydrocarbon gas dissolved in mud. A fresh mud sample is injected into a chamber and steam is used to elaborate the contained gas from mud. This is then sucked out using a special syringe and injected into the chromatograph for the analysis.

The gas systems are calibrated using minimix test gases containing C1 - C5 hydrocarbons and are checked regularly. The H₂S sensors can also be checked using ampoules or low concentrations and any necessary adjustments is made.

GAS TRAP ASSEMBLY

The Baroid mud gas trap is an electric motor driven device giving a combination function of agitator and fluid pump power is supplied to the motor from the logging unit through the 110V distribution system. The motor drives an impeller enclosed within the stainless trap chamber which is immersed in the flowline mud flow. The mud enters the trap body through a variable diameter opening in the base of the chamber where it is agitated into a vortex by the impeller. The vortex throws the mud upwards on the inside wall of the chamber and liberates any entrained gases through the action of the vortex, and the agitating effect of the impeller. The mud exits through

an opening in the side of the trap chamber. The gas and air mixture is drawn-off through the top of the chamber at 6 CFH (Cubic Feet/Hour) and drawn through a series of moisture and dust filters prior to being distributed in the detector, the chromatograph and the CO₂ detector.

40. FID GAS DETECTOR

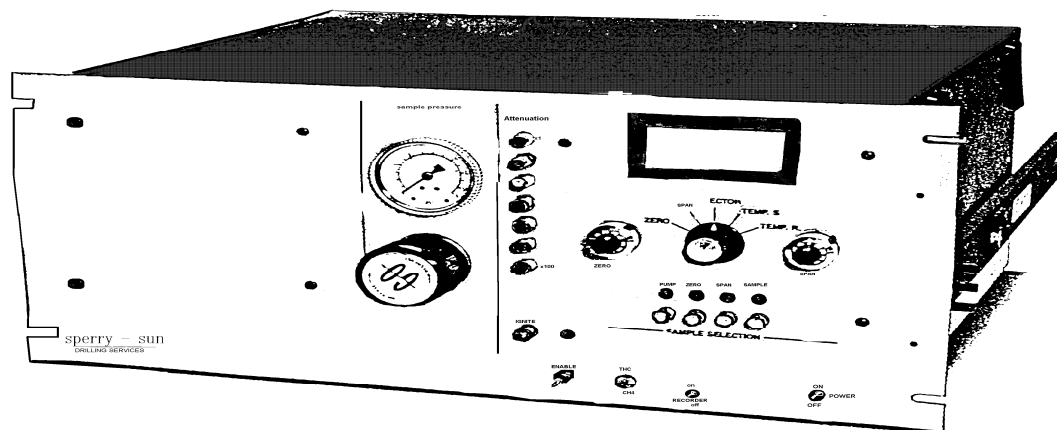
Flame ionization detector

I - Introduction

The Flame Ionization Detector (**FID**) is a relatively new type of gas detector to find its way into the oil field. For many years the only type of gas detector available was a thermal conductivity (TC) or Hot-Wire type detector. These detectors were troubled by a drift lack of sensitivity, difficulty in calibration, short filament life and a very non-linear output. The **FID** addresses many of these problems and provides an accurate measurement of the amount of gas in the trap sample.

The Total Hydrocarbon Analyser (THA) is an FID gas detector manufactured for Sperry-Sun by Baseline Industries Inc, of Lyons Colorado. Sperry-Sun has incorporated this instrument into the MWD system (LS-2000) along with a Total Hydrocarbon Conditioner (THC) to control the system flows and provide the logger with a flexible, highly accurate, easy to operate and easy to calibrate gas detector. Sperry-Sun also uses a Baseline Industries FID gas chromatograph together with the THA and a good correlation of data between the two instruments is achieved.

The following section is designed to acquaint the logger or technician with the THA and THC.



II - Operating Principle

When many organic compounds are burned in a hydrogen flame, charged particles or ions are given off. Hydrocarbons from the formation during drilling are among these organic compounds. The common hydrocarbons that are detected from the sample gas are methane (CH₄), ethane (C₂H₆), propane (C₃H₈), normal & iso-butane (C₄H₁₀) and pentanes (C₅H₁₂).

The gas to be sampled is drawn into the FID gas detector from the trap motor. Only about 1 % of the sample gas is actually burnt in the flame whereas the remainder is vented.

The gas which is going to the flame is mixed with air as a make-up and hydrogen as a carrier. Another flow stream of combustion air is routed to the flame separately to help support the combustion process.

As the sample is burnt in a clear hydrogen flame the released ions or free electrons are forced to travel as a small current into an amplifier called the electrometer.

The current flow is extremely small on the order of 10^{-9} to 10^{-12} amperes and the electrometer produces a voltage proportional to this current.

In this way the voltage generated is proportional to the amount of hydrocarbons present in the sample.

Advantages of the FID

- 1- it is about 1000 times as sensitive as the thermal conductivity detector for measuring hydrocarbons.
- 2- It has much more linear output than the thermal conductivity detector.
- 3- it is not sensitive to carbon dioxide, hydrogen sulfide, water vapour or hydrogen.
- 4- In mud logging applications the FID is only sensitive to the hydrocarbons which are released from the formation.

Figure 1 shows the FID assembly.

III - Output from an FID

Output from an FID is similar to the TC in that the total output is the sum of the responses from the different gases contained in a sample. An advantage of the FID is that the output are linear as the gas concentration in air increases and the output can be easily converted to give the true amount of hydrocarbon present. For instance suppose that an FID gas detector is calibrated to give a reading of 1.0 % on the digital meter for a one percent concentration of methane in air. Heavier gases give proportionately greater responses.

1 % methane (CH₄) in air reading = 1.0

1 % ethane (C₂H₆) in air reading = 1.5

1 % propane (C₃H₈) in air reading = 2.0

1 % n-butane (C₄H₁₀) in air reading = 2.5

1 % iso-butane (C₄H₁₀) in air reading = 2.5

A one percent mixture of all the above gases would give a reading of 9.5 or the sum of the individual gases. Ethane yields 1.5 times the response of methane because 6 hydrogen ions are released during combustion i.e 1.5 the number of electrons. Propane and butane respond in alike fashion yielding 2 and 2.5 times the free electrons. So, the output of an FID is described as “percent equivalent methane” . Using the example, a

one percent mix of the five gases in air would be known as 9.5 percent equivalent methane.

This is the same output that a 9.5 percent concentration of methane in air only would give. A chromatograph is necessary to provide the actual analysis of the sample gas.

Other advantages of the FID

- 1- Using both an FID gas detector and chromatograph is useful because the data from the two instruments will easily correlate. The logger will then have an easier time making sure that both instruments are operating correctly.
- 2- The THA or gas detector can pick up rapid changes in the volume or ratio of gases coming from the hole. A sudden change in the THA output would flag the logger that a volume or ratio change had occurred and he should run a chromatogram. Since the contributions of the various gases in a TC detector are more equal than in a FID, The ratio or volume change wouldn't be picked up as fast. The logger wouldn't have as good or as fast data with a TC detector telling him that a significant change had occurred.

41. FID GAS CHROMATOGRAPH

The FID gas chromatograph used by Sperry sun logging systems is The Baseline model 1030A.

The Chromatograph has a twin column and is fitted with a flame ionization filament. It is programmable and all functions are controlled through an On-Board microprocessor. It has a selectable signal attenuation which allows for a great degree of accuracy throughout a range of hydrocarbon gases encountered.

Full analysis of a sample gases from C1 through to C5 requires approximately 8 minuets with off-line type, and it takes 3 minuets with the On-Line type in which the carrier air is replaced by hydrogen.

The microprocessor units enables the operator to program the shorter of the two columns (The cut-off column) to choose the required level of analysis. After passing through this column the sample is directed through the longer column to separate the components.

The facility to program an automatic attenuation is useful where one type of hydrocarbon may be present in large amounts and another in small amounts.

The system can be programmed for manual (injection) or automatic operation (direct from gas trap) with an optional of auto-recycle. Before each cycle the system performs an auto-zero function.

The principle of operation is the same as with the FID gas detector, but where the gas detector is always fed with a mixed sample, the chromatograph takes a 1CC sample and separates the mixture to its components by passing through a column. The separation takes place inside the column according to the different elution times due to the varying absorption and adsorption rates of the component gases as they are pushed through the column.

The sensitivity is 1 ppm but, in normal operating practice a sensitivity of 10 ppm is assumed. Normal programming is for C1, C2, C3, C4-iso, C4-normal and C5's.

In the case of the Off-Line chromatograph the output is displayed on a time driven wide track chart recorder, giving a permanent graphical record of each cycle.

In the On-Line chromatograph the FID signal is completely processed by the LS-2000 computer system and the output of each cycle is printed out on a computer printer as well as being stored in the computer buffer as records. These stored records can then be transferred to the PC and plotted on various logs forms.

9. SENSORS

42. SENSORS SPECIFICATIONS

The nature of the Logging system data acquisition systems allow complete flexibility in the choice of sensor inputs. The number of analogue sensors can readily vary with up to 64 inputs available. This means that additional sensors to those outlined below can be added upon request with minimal effort.

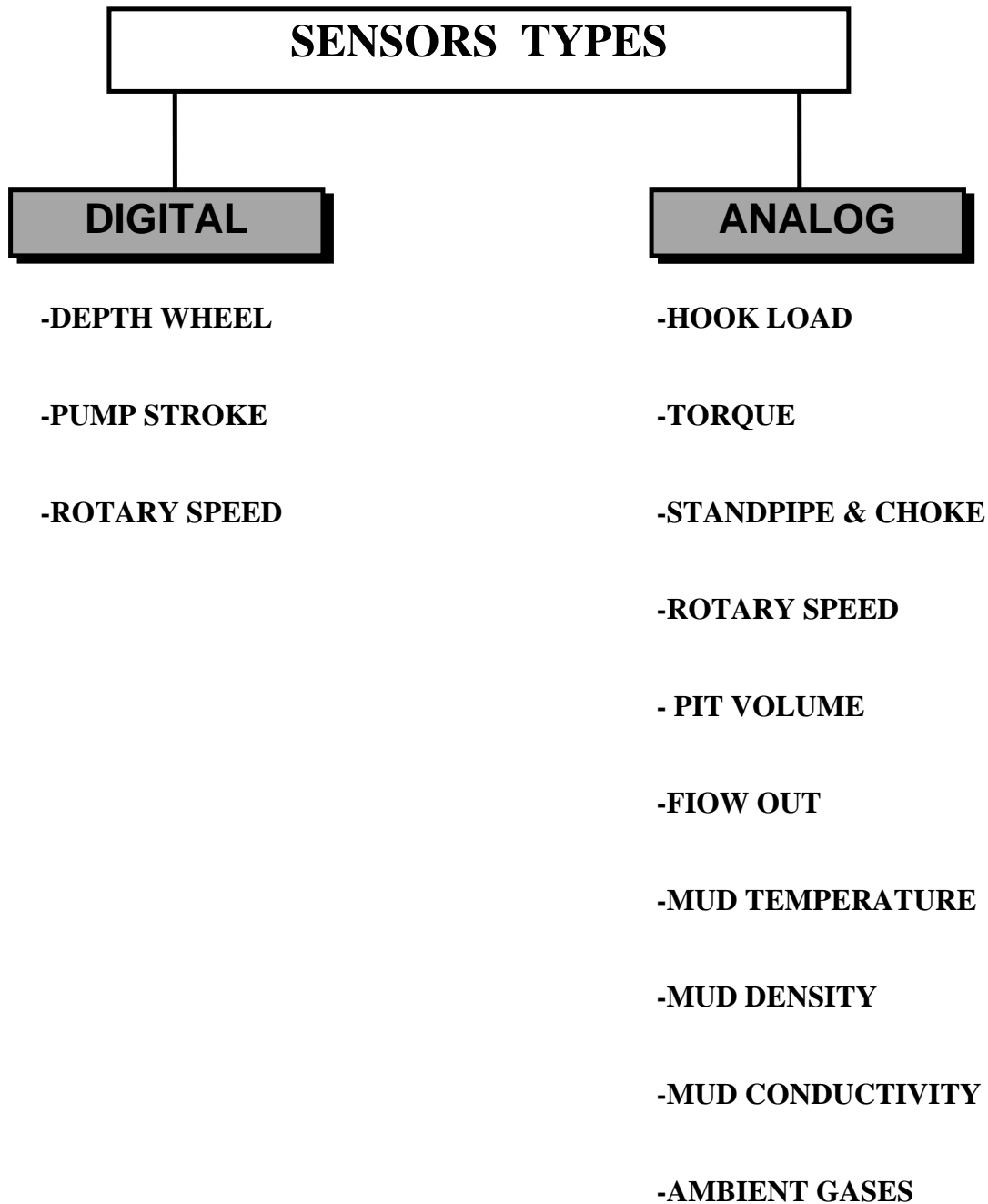
Standard sensors list:

- Depth wheel
- Hook load
- Rotary speed
- Torque- Electrical..or.. mechanical
- Standpipe & choke Pressure
- Pit volume- delaval
- Flow out - paddle
- Pump stroke
- Mud temperature In/Out
- Mud density - differential; In/Out

Mud conductivity

Optional sensor list

- Mud density - resonant
- Flow out - magnetic inductive
- Pit volume - ultrasonic
- Quantitative Fluro Techunique; QFT
- Quantitative Gas Measurments; QGM
- Dissolved H₂S; Mud Duck
- Wireline depth
- Redact potential
- PH
- Dissolved oxygen
- Solids content
- Portable Density meter

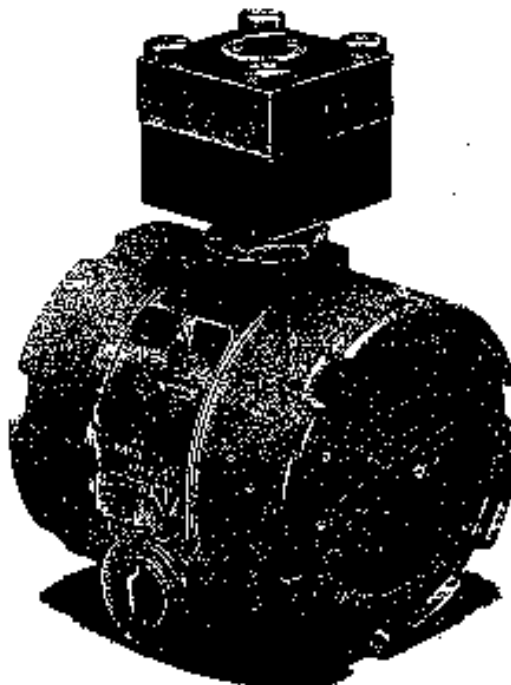


1.HOOK LOAD SENSOR

The Hookload sensor normally used is a pressure transducer which ties into the rig's deadline anchor system. The standard configuration uses a Rosemount E-1144-GO - 600 psi pressure transducer. The span of the sensor can be varied from 0-150 psi to 0-600 psi to match the rig system and provide the optimum signal range. High capacity hookload system may need a 0-1200 psi system.

The sensor is provided with 24 VDC excitation and produces 4-20 m.a. signal. This is processed by a signal conditioner card to give a 0-10VDC analogue signal to the computer. The use of the current signal on this sensor provides a signal which is liable to lower interference and provides a faster and more accurate response for the computer.

A pancake type load cell is available as an option. This utilises the normal sensor but ties in to a Martin-seeker pancake cell mounted directly on the deadline.

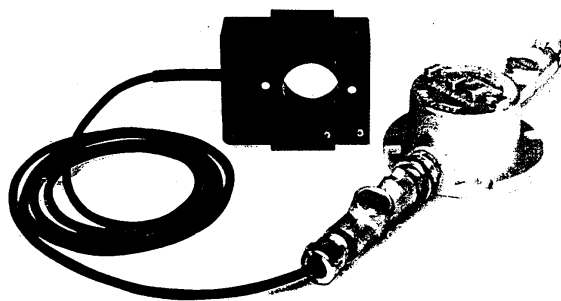


2.TORQUE SENSORS

Electric torque type:

The electric torque sensor is an induced current device with a split coil. The sensor is clipped around the rotary table power cable at any convenient point and measures the

rotary table current in amperes. As an option absolute torque can be monitored by combining the electrical torque sensor with a voltage measurement sensor fitted in the rotary motor power distribution cabinet.



Changes in the magnetic field around the power cable are detected by 2 **Hall Effect** probes and converted into a signal directly proportional to the current flowing. These are amplified by the signal conditioner to provide The computer with a 0-10 VDC analogue signal.

The computer also calculates and databases on-line torque deviation. This is the variation from the average torque through an interval. It is useful for PDC bit drilling optimisation and bit wear analysis.

Mechanical torque type:

A pressure transducer and connections similar to the hookload sensor are used for the mechanical torque sensor. The sensor is tied directly into the rig's hydraulic rotary torque system.

3. STANDPIPE AND CHOKE PRESSURE SENSORS

1. Strain gauge type:

The Standpipe and Choke Pressure Sensors use a Dynisco strain gauge transducer. The transducer consists of a box of four resistors. An excitation voltage of 15 VDC is applied to one corner and the excitation ground are taken-off from the opposite corner. The strain gauge resistors are made from silica crystal, which has the property of changing resistance with changing pressure applied across crystal. Note that in essence, the sensor contains two resistor divider networks with the two signal wires in the middle of each. One side has a fixed resistance and thus a fixed output (signal-) while the other has a variable resistance which results in a variable output (signal+). The signal conditioner card provides the 15 VDC excitation voltage and an amplifier circuit to produce a 0-10 VDC signal to the computer.

The only difference between the standpipe and choke sensors is the type of transducer fitted. All sensors are tested to 15,000 psi.

2. Current loop type:

This sensor measures the mud pressure by a direct contact with a pressure transducer. The standpipe sensor has 0-6000 psi transducer is normally specified. Both types of transducer are located in a housing with WECO knockon connector rated for 15,000 psi working pressure.

The transducer normally uses 24 VDC excitation and its output is 4-20 m.a. .

The transducers normally used are either Dynisco 4 wire PT11 ,or in the case of the North Sea Dynisco PT 386 two wire 4-20 m.a. transmitter.

PT 11 sensor mounted on choke manifolds rated for 15,000 psi test/working pressures will require a hydraulic tie-in to the rig's pressure booster on the manifold and a 0-6000 psi sensor connected into the booster line.



For 15,000 psi working pressure choke manifolds, the Dynisco PT 386 0-15,000 psi sensor can be supplied to special order.

In some situations it may be necessary to tie-in to the Martin Decker pressure converters on the standpipe or choke manifold. The Rosemount E 1144 transducer (similar to the Hookload sensor) is usually used for this application.

7.ANALOG ROTARY SPEED SENSOR

The unit consists of a small low-power D.C. generator. This generator is driven via a belt and pulley from the rotary table drive shaft.

The unit produces 7 VDC per 1000 Revolution Per Minute (RPM).

The Final RPM will depend upon the gearing. The DC signal is isolated through a signal conditioner electronic board .

8.PIT VOLUME SENSORS

The pit monitoring system uses a **Delaval** sensor to monitor individual pits. The computer system allows a total flexibility in defining the active and reserve pit systems. The configuration can be changed quickly through the keyboard. Alarms are computer controlled and can be set up for low and high levels on the active system, the reserve system, or on individual pits. The system can monitor up to 16 pits.

On trips the gain tank and trip tanks are also assigned through the trip monitoring programme for complete coverage of the pit system.

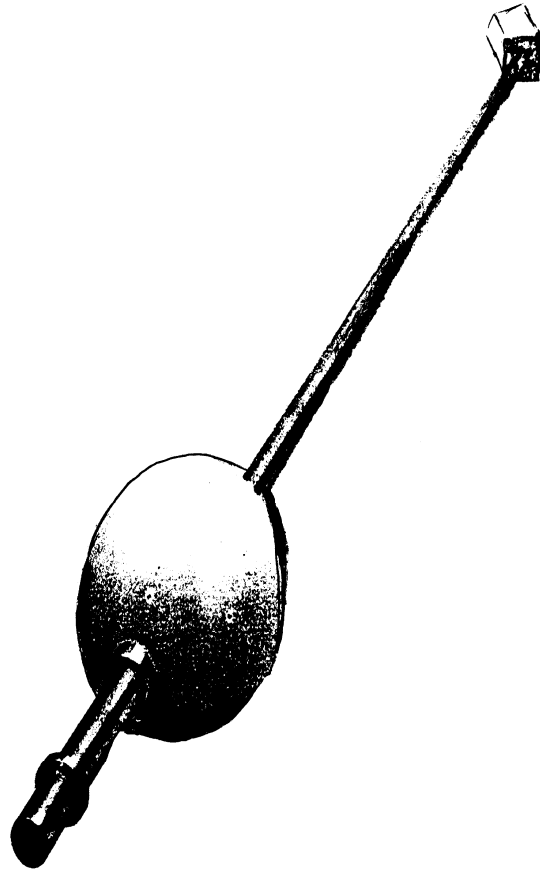
On connections the expected flow back gain encountered at various pump rates is entered. The system can correct for alarm if unexpected changes are seen during the connection.

Delaval sensor use a non contacting magnetic float activate discrete reed switches in reed switch resistance string inside a stainless steel pole. The position of the float determines the resistance and hence the voltage fed to the computer.

The system is very robust and has been field proven for years as the simplest and most reliable of pit measurement in standard situations.

If access is severely restricted or the pits are deep, we use ultrasonic sensor. The **Endures and Hawser DU 523 Z** is normally specified. These have microprocessor based filtering in the sensor to condition the signal and reject spurious echoes, temperature compensation self monitoring for faults and a simple calibration procedure.

Ultrasonic



9.FLOW OUT SENSORS

Flow Padle Type

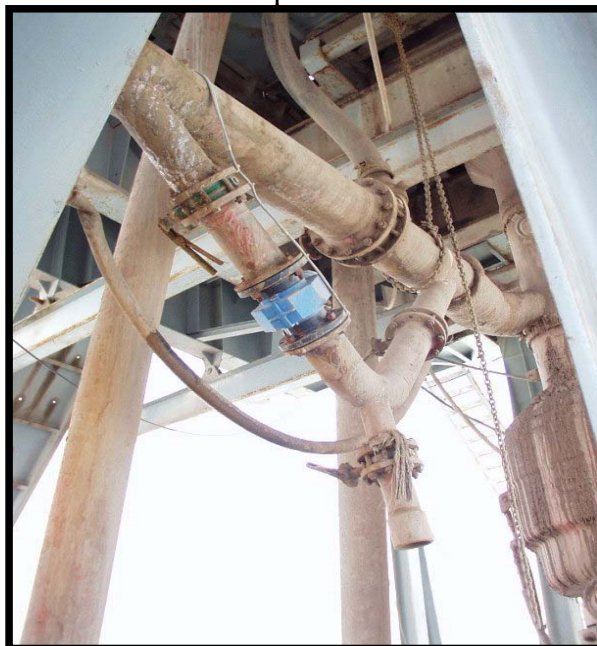
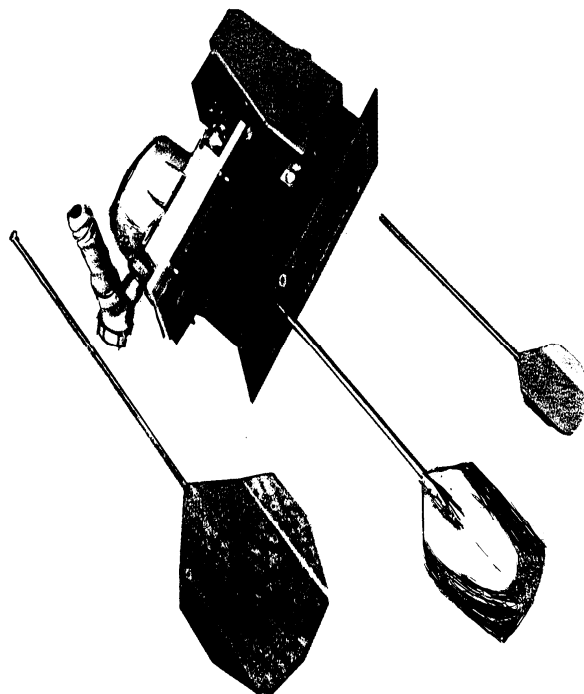
The flow out sensor normally specified is of the paddle type. Flow in the flowline causes a rotation of the paddle and a corresponding rotation of a 1 turn potentiometer. Various paddle sizes are available to suit the different flowlines. Non-linear and logarithmic calibrations in the computer allow accurate calibrations to be made for most installations over a wide range of flows.

The sensor is supplied with a 10 VDC excitation supply which is fed through the 10 KOhm, one turn high accuracy potentiometer. This gives a signal output of 1-10 VDC. This analogue signal is input directly to the computer. If a pressure rated flow sensor is required for installation on offshore diverted systems, a Martin-Decker MFTX05A non-contacting mud flow sensor can be supplied on request. The paddle flow sensor is a well proven and rugged instrument. However the accuracy of its measurement depends on the installation in the flowline. As the flow in the flowline is such an important measurement for the well and rig safety we recommend the installation of a magnetic flowmeters for long term contracts and where the rig's construction allows. The magnetic flowmeter has to be mounted in a section of the flowline which is full to provide an accurate measurement. The most recent designs of meter will work in fluids with a conductivity above 1 micro mho/cm. In practice this will allow use in most field oil base muds.

Electromagnetic Wave Type (EWS System)

The sensor is installed in a closed V-shaped piping and measure the flow through generating induction voltage in a magnetic field.

The v- shaped piping is designed to keep the inside of the sensor always filled with fluid.



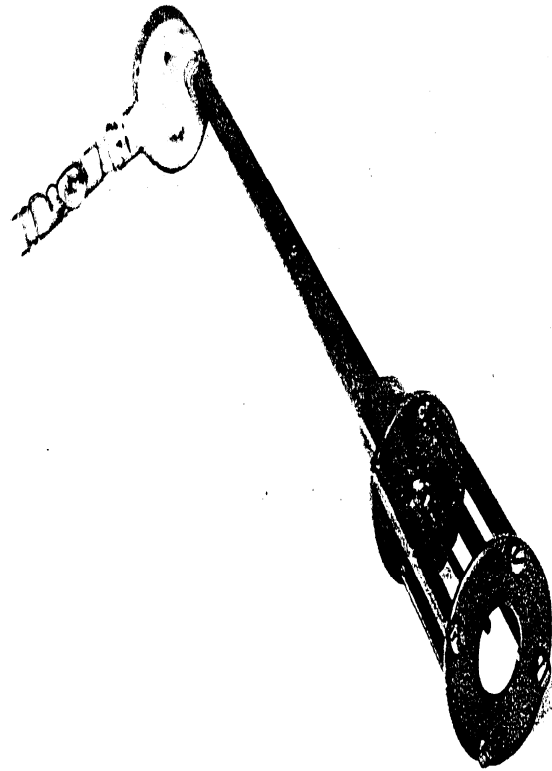
10.MUD

TEMPERATURE SENSORS

Two types of temperature sensor are in use. Either semiconductor thermistor transducers or platinum resistance elements (PRT) are used. These are mounted in a protective cage at the end of all sensor poles. The **Temperature-In** sensor is mounted in the suction pit and the **Temperature-Out** sensor in the shaker header box.

The thermistor sensor is supplied with an 8.5 volt excitation voltage. The current output of the sensor is dependent on temperature and varies linearly between 270 and 370 microamps. This signal is converted by the signal conditioner card into a 0-10 VDC analog signal for input into the computer.

The **Platinum Resistance** element has a 4-20 m.a. converter in the sensor head and uses a 24 VDC excitation voltage from the signal conditioner.



11.MUD DENSITY SENSOR

The Mud density sensor is of the differential pressure type. Two silicon oil filled diaphragms are placed one foot apart in the drilling mud and a highly accurate differential pressure transducer interrogates the readings and transmits a 4-20 m.a. signal to the computer.

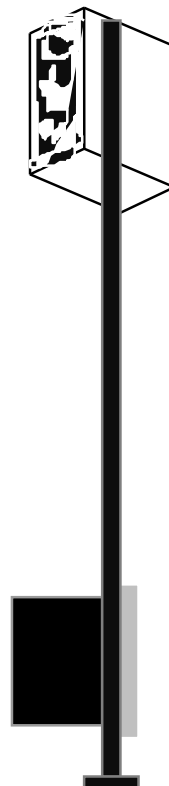
The sensors are mounted in the suction pit and in the shaker header box to provide the density In&Out measurements.

The span can be adjusted over the desired range through calibration the sensor head.

The sensor is supplied with 24 VDC excitation supply and produces a 4-20 m.a. signal. This enters a signal conditioner card and is fed to the computer as a 0-10 VDC signal.

For long term rig installations we recommend the resonant density sensors. Their superior accuracy and reliability give an on-line density reading that can be used with confidence by the customer and rig operator.

These sensors can be mounted in the mud pump suction lines. This allows the sensors to pick up the density of the fluid being pumped.



The sensors rapidly detect the presence of the wrong fluid being pumped and can save rig time and money by early detection of miss-aligned pits. Unlike differential pressure sensors they are unaffected by turbulence in the pits and they maintain accurate calibration over long periods.

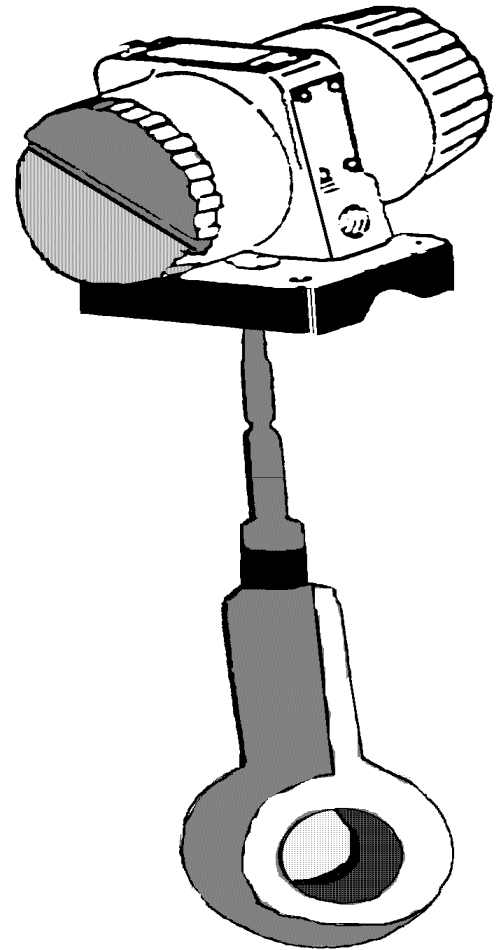
12. MUD CONDUCTIVITY SENSOR

The sensor is a new 4-20 m.a. type which has all the electronics in the sensor head and gives a 4-20 m.a. signal to the unit. This signal is then put through a density (or new conductivity) signal conditioner card (both are exactly the same) to produce a 0-10 VDC signal for the computer.

Principle of operation:

The sensor works on the principle of the toroidal coupling effect. The sensor contains two coils, known as the primary and secondary coils. AC current is fed to the primary coil by a Oscillator. The magnetic effect caused by this current is transmitted to the secondary coil by the medium surrounding the coils. This produces a current in the secondary coil, whose phase difference is related to the resistivity of the medium. The phase difference by a demodulation unit and then amplified to a 4-20 m.a. signal. The sensor also contains a thermistor for temperature compensation, so that the actual value given is at it's 20° equivalent.

The 4-20 m.a. signal from the sensor is conditioned through a density/conductivity signal conditioner and then fed to the computer as a 0-10 VDC.

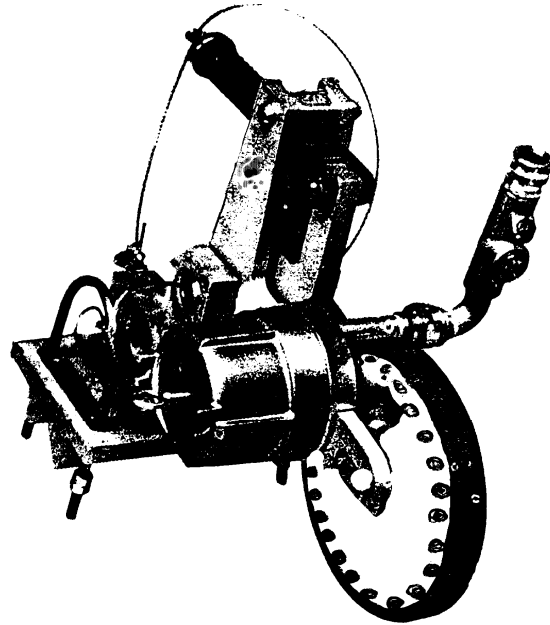


13. DEPTH SENSOR

Depth is monitored through an intrinsically safe encoder wheel mounted on the crown sheaves on land rigs, jackups and platforms. On semi-submersible rigs either a wire line retriever is mounted on the rig floor to provide very accurate kelly height or a combination of compensator opening sensor and crown wheel is used. The depth system provides continuous monitoring of depth, rate of penetration, running speeds, kelly, block, compensator and riser position. The system is fully operative during tripping and other rig activities and also calculates bit off-bottom depth and running speed. This allows the calculation and display of swab and surge pressures while tripping.

The crown type :

The depth wheel sensor assembly is mounted against the slow sheave of the crown wheel. It consists of a rotating wheel, twenty four inches in circumference. Two proximity switches detect the wheel's movement. The proximity switches produce a quadrate signal which can identify the direction of movement of the wheel. The digital pulses from the switches are converted to up or down digital signals for computer.



When monitoring depth on a floating rig, a second depth wheel is mounted on either the riser tensioners or the guide base tensioners to monitor rig heave. A wireline retriever assembly and encoder are mounted on the rig floor and a line is run to the kelly to provide heave compensated kelly movement. A compensator opening sensor utilizing a digital encoder can alternatively be used in conjunction with the crown wheel.

The depth system measurements are combined to provide very accurate depth monitoring even during severe roll and heave conditions.

The Draw work type

This is smaller and more simple type of depth sensors which is mounted on the draw work. It is used only with the IRIS data acquisition and is not used in the LS 2000 system.

14. PUMP STROKE SENSOR

The pump rate is monitored by non-contact magnetic proximity switches, mounted over the pony rod end clamp. The BLS 2000 can monitor up to six pumps continuously. The system can assign any combination of the pumps to the active and the auxiliary pump counters, which then monitor individual pump rates and total strokes. It calculates the total volume pumped, bottoms up, well circulation times and lags.

In certain installations, a whisker type limit mechanical switch sensor may be installed if the pump configuration is unsuitable for the non-contact proximity switch.

The sensor is supplied with a 24 VDC excitation voltage and feeds back a digital. This output is isolated by a signal conditioner card passed to the computer for processing.

15. DIGITAL ROTARY SPEED SENSOR

Rotary table revolutions are normally measured with a digital encoder mounted in the rotary drive system. The sensor is driven by a flexible belt around the rotary motor shaft.

The sensor uses an encoder which gives one hundred counts per revolution of the encoder shaft. On most installations this is equivalent to 200 counts per rotary RPM giving high resolution and accuracy.

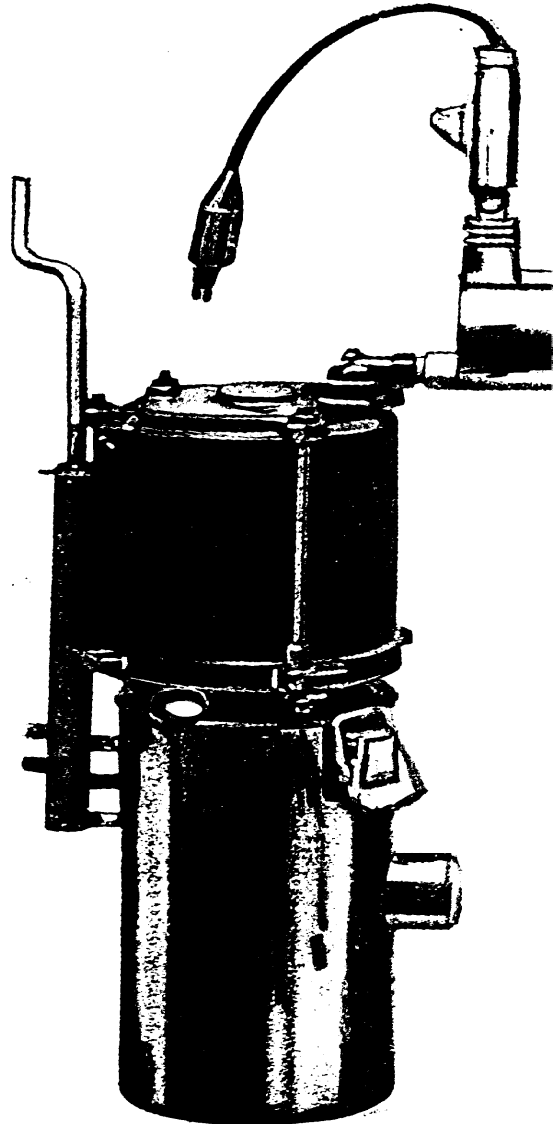
Two types of encoder are used. For the North Sea sector Pepper and Fushs transformer isolated barriers is used to provide a certified L.S system. Other units use an American Optical encoder which is supplied with a 24 VDC excitation and delivers back a 24 VDC digital signal to the digital signal conditioner board then to the computer.

The signal is calibrated by entering a calibration factor which converts the digital counts into RPM.

A Pepper and Fuchs proximity switch can also be utilised on the drive shaft to provide a non-contacting measurement system.

16. GAS TRAP ASSEMBLY

The mud trap assembly comprises an electric motor, impeller and trap chamber. 110 volt power is supplied to the motor from the unit and the wattage used is monitored to indicate the status of the trap in the mud. For example, a reduced wattage may indicate that the mud level has fallen below the trap housing requiring adjustment. The mud enters the trap through an opening in the base of the chamber where it is agitated into a vortex by the impeller. The vortex throws the mud upward on the inside wall of the chamber and liberates entrained gases. Air is drawn in through an opening in the trap body, mixes with any liberated gases and is carried via the hose at 6 cubic feet per hour to the unit. After passing a series of moisture and dust filters the air/gas mixture is distributed to gas detector, chromatograph and other ambient detectors (CO₂, H₂S etc).



17. HYDROGEN SULPHIDE GAS DETECTOR - H₂S

The Crowcon gas detection system is used to select and monitor H₂S gas levels at various sensing points at the rigsite. Sensors are usually installed at the bell nipple shale shaker, mud room and rig floor.

A ten channel Gas Warden is used with from 1 to 10 sensors available as needed. The electrochemical sensor contains a sensing electrode, electrolyte, counter electrode and reference electrode. Hydrogen sulphide gas diffusing to the sensing electrode is electrochemically oxidised and at the counter electrode, oxygen supplied from ambient air is reduced. The overall effect of these two reactions is a current that flows through the sensor and into the head amplifier via electrical leads. This current is directly proportional to the concentration of hydrogen sulphide being monitored. To measure H₂S which may be dissolved in the drilling fluid a Delphian "Mud Duck" can be made available. This instrument measures the total soluble sulphides, pH and H₂S hazard potential. The Mud Duck operates in water base muds with a pH of between 8 and 12. Nevertheless in areas where H₂S is known to be a hazard the mud Duck can give the earliest indication of acidic contaminants in the mud.